2018 ABAER 001

Alberta Energy Regulator

TransCanada Pipelines Limited

Applications for the White Spruce Pipeline Project
Fort McKay Area

February 22, 2018

Errata

March 13, 2018: The pipeline diameters in paragraph 2 were corrected.

- Original: "The first pipeline would be 508 millimeters (mm) in diameter and about 50 metres (m) in length. The second pipeline would be 323.9 mm in diameter and 71.5 kilometres (km) in length."

Alberta Energy Regulator
Decision 2018 ABAER 001: TransCanada Pipelines Limited; Applications for the White Spruce Pipeline Project, Fort McKay Area

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Decision

[1] The Alberta Energy Regulator (AER) approves the two applications TransCanada Pipelines Limited (TransCanada) made under the *Pipeline Act* (1866519 and 1866521) and the fifteen applications it made under the *Public Lands Act* (PLA160525, PLA160526, PLA160527, PLA160529, PLA160530, PLA160531, PLA160532, PIL160286, PIL160287, PIL160288, PIL160289, PIL160321, PIL160376, LOC160846, and LOC160995) subject to the conditions in appendix 1.

Background

[2] TransCanada applied to construct two crude oil pipelines (the White Spruce pipeline project). The first pipeline would be 323.9 millimetres (mm) in diameter and about 50 metres (m) in length. The second pipeline would be 508 mm in diameter and 71.5 kilometres (km) in length. The project would deliver synthetic crude oil (SCO) from Canadian Natural Resources Limited's (CNRL's) Horizon processing plant to the Grand Rapids Pipeline GP Ltd. MacKay Terminal for delivery to markets.

[3] Fort McKay First Nation (Fort McKay) was the only participant in the hearing. The project would be located within Fort McKay's traditional territory. Extensive industrial development exists within Fort McKay's traditional territory. These developments include oil sands mines, in situ oil sands projects, upgraders, roads, pipelines, and transmission lines. The project would come within 7 km of the Hamlet of Fort McKay, Fort McKay's residential settlement (figure 1).

[4] Fort McKay holds treaty rights under Treaty 8 and aboriginal rights that include rights to hunt, fish, trap, and gather culturally important natural resources for social, cultural, and consumption purposes as well as to use and enjoy their reserve lands. The project would involve multiple water crossings, including at the Dover and Mackay Rivers, which are important to community members for fishing, hunting, harvesting, and general enjoyment. The project's route would be colocated with other existing linear disturbances but would enlarge the environmental footprint.

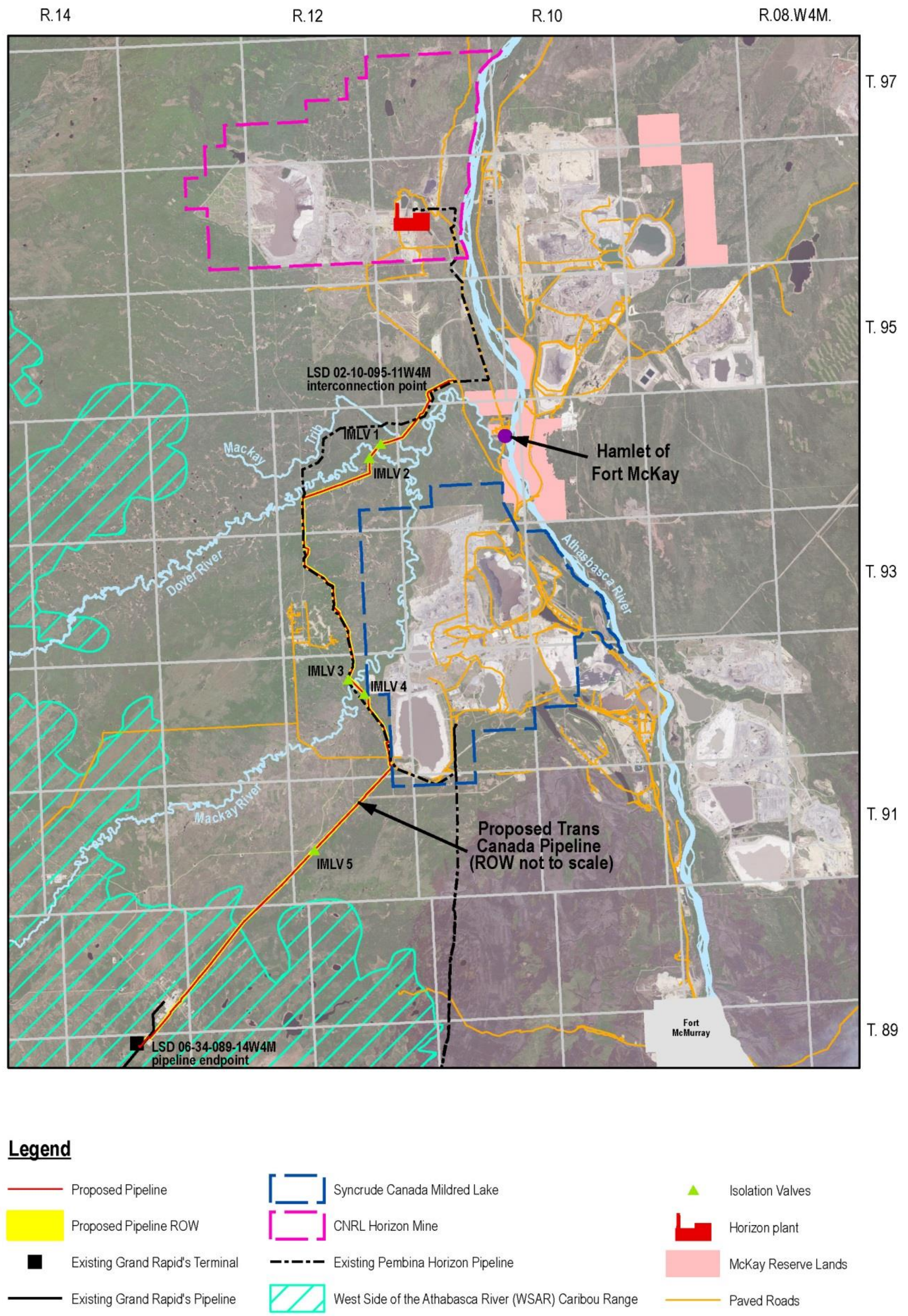

Figure 1. Project area

Applications

[5] On September 7, 2016, TransCanada applied to the AER to construct and operate the two crude oil pipelines. The shorter pipeline would start at a pipeline riser at Legal Subdivision (LSD) 2, Section 10, Township 95, Range 11, West of the 4th Meridian (02-10-095-11W4M) and would end at a TransCanada meter station. The longer pipeline would start at the TransCanada meter station (03-10-095-11W4M). It would end at the Grand Rapids Pipeline GP Ltd. MacKay Terminal (06-34-089-14W4M).

[6] TransCanada submitted two applications (1866519 and 1866521) under the *Pipeline Act* and fifteen applications under the *Public Lands Act*. The public lands applications include seven pipeline agreements (PLA160525, PLA160526, PLA160527, PLA160529, PLA160530, PLA160531, and PLA160532), six pipeline installations (PIL160286, PIL160287, PIL160288, PIL160289, PIL160321, PIL160376), and two licences of occupation (LOC160846 and LOC160995).

Statements of Concern

[7] The following parties filed statements of concern in response to the applications:

- Athabasca Chipewyan First Nation
- Fort McKay First Nation
- Fort McKay Métis Community Association
- Métis Nation of Alberta Association Fort McMurray Local Council 1935 (McMurray Métis)
- Mikisew Cree First Nation
- Suncor Energy Inc.

Hearing

[8] The AER decided to hold a hearing to consider the applications. The hearing was held before hearing commissioners R. C. McManus (presiding), C. Chiasson, and P. Meysami. They issued a notice of hearing on June 1, 2017, which set deadlines for filing requests to participate. The AER received requests to participate from Fort McKay, McMurray Métis, and Athabasca Chipewyan First Nation. The hearing panel decided that Fort McKay and McMurray Métis could participate. On July 26, 2017, McMurray Métis advised that they did not intend to participate in the hearing. Fort McKay was the only participant in the hearing. Those who took part in the hearing are listed in appendix 2.

[9] The parties proposed a written hearing process. The commissioners determined that a written hearing process with oral final argument would take place. The first evidence and submission by TransCanada was due on August 1, 2017.

[10] The AER must request advice from the Aboriginal Consultation Office (ACO) on whether actions may be required to address potential adverse impacts on existing rights of aboriginal peoples or traditional

uses before making a decision about an energy application for which First Nations consultation is required. The ACO was given all relevant notices and materials related to the *Public Lands Act* applications for this project.

[11] The panel closed the evidentiary portion of the hearing on October 23, 2017, subject to receiving the ACO's hearing report. The ACO provided its report on November 16, 2017. The oral final argument was held in Calgary on November 29, 2017, and the hearing was closed on that day.

Legal Framework

[12] As set out in section 2(1) of the *Responsible Energy Development Act* (*REDA*), the AER's mandate is to provide for the efficient, safe, orderly, and environmentally responsible development of energy resources in Alberta. We, the panel presiding over this hearing, must therefore decide whether approving this project is consistent with the AER's mandate.

[13] In addition, although not explicitly set out in *REDA* or in any of the other legislation administered by the AER, as a statutory decision maker, the AER is required to consider potential adverse impacts of energy resource applications and activity on existing rights of aboriginal people and the exercise of those rights.

[14] The *Aboriginal Consultation Direction*, Energy Ministerial Order 105/2014 and Environment and Sustainable Resource Development Ministerial Order 53/2014, and the *Joint Operating Procedures for First Nations Consultation on Energy Resource Activities* direct how the AER must deal with proceedings where First Nations consultation is required by the ACO. The direction applies in this matter to TransCanada's applications under the *Public Lands Act*. The ACO provided two separate consultation assessment reports, which we considered when making this decision.

[15] In making this decision, we must consider the factors set out in section 3 of the *REDA General Regulation*, including the effects of the proposed pipeline project on the environment.

[16] In addition, our decision needs to be consistent with the purposes and provisions of the *Public Lands Act* and the *Pipeline Act*. The panel may examine any matter relating to the observance of safe and efficient practices in the construction and operation of pipelines.

[17] In reaching our decision, we have considered all relevant materials constituting the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the AER's reasoning on a particular matter and do not mean that the AER did not consider all relevant portions of the record with respect to that matter.

[18] Based on the legislative framework above and the evidence of the parties, the panel has determined that the following are the key issues and questions:

- Is the project needed to provide for the efficient and orderly development of Alberta's energy resources?
- What are the potential adverse effects on aboriginal participants and can they be adequately mitigated?
- What are the potential environmental effects of the project and can they be adequately mitigated?
- Is the project designed in a way that it can be constructed and operated safely?

Project Need and the Efficient and Orderly Development of Alberta's Energy Resources

[19] TransCanada said the pipeline is needed to transport an expected increase in SCO from the phase 3 expansion of CNRL's Horizon processing plant (Horizon plant). SCO from the Horizon plant is currently transported through the Pembina Horizon pipeline system (Horizon pipeline). Fort McKay argued that the existing Pembina Horizon pipeline system could handle increased SCO from the phase 3 expansion. They maintained that additional pipeline capacity is not needed.

[20] To determine whether the project is needed, we assessed

- the total SCO production expected from the Horizon plant after the phase 3 expansion,
- the transportation capacity of existing pipeline facilities,
- if increased production from the Horizon plant would exceed the existing transportation capacity, and
- whether other options existed to transport increased production from the Horizon plant.

[21] We conducted our review considering section 6.9.28 of AER *Directive 056: Energy Development Applications and Schedules.* Under this directive, pipeline development in Alberta should avoid proliferation of pipelines whenever possible and practical. Pipeline proliferation occurs when new development disturbs the surface and affects the public to a greater extent than if existing infrastructure had been used.

Expected Production at the Horizon Plant

[22] TransCanada and Fort McKay gave conflicting evidence on the production capacity of the Horizon plant and how much SCO would be produced by CNRL once the expansion of the Horizon plant was complete.

- Fort McKay argued that the AER approval for the Horizon plant limits CNRL's annual average production to 232 000 bbl/d. They stated that the Horizon plant could have a maximum daily production capability of 250 000 barrels per day (bbl/d), but that level of production could not be reached as an annual average due to AER approval limits.

- TransCanada submitted that the phase 3 expansion of the Horizon plant would increase production capacity of SCO. TransCanada submitted that after this increase, CNRL would target an annual average production of 250 000 bbl/d and not 232 000 bbl/day. It asserted the Horizon plant maximum daily production would be 282 000 bbl/d. TransCanada arrived at 282 000 bbl/d by assuming that the Horizon plant would undergo complete shutdown 41 days a year, during which no SCO would be produced. It calculated that to achieve the 250 000 bbl/day annual average target, CNRL would have to produce 282 000 bbl/d of SCO the remainder of the year when it is operating to compensate for the missed production during the 41 days of complete shutdown.

[23] We note that both parties cited CNRL public information that, following completion of phase 3, the Horizon plant would have a production capacity of at least 250 000 bbl/d and, likely, additional production greater than that.

- A CNRL press release dated August 3, 2017 (cited by Fort McKay's expert witness), states the following about production capacity (appendix 3):

> [CNRL] will see incremental production gains throughout the completion of future expansion and debottlenecking, with targeted full facility capacity of approximately 250,000 bbl/d. Further phases of expansion could potentially bring the ultimate capacity to 500,000 bbl/d.

- A second press release also dated August 3, 2017 (cited by both parties), states current and future production from the Horizon plant as follows (appendix 4):

> A significant amount of process engineering to determine the capacity outcomes of all the critical components of the upgrading operation was completed at various confidence levels. As a result it is not prudent at present to predict with confidence, that Horizon will be able to deliver production levels exceeding 250,000 bbl/d of SCO until [CNRL] has actual throughput through the upgrader and the actual reliability is determined once phase 3 is operational.
>
> [CNRL] is confident that increased reliability and creep capacity volumes will be attainable if work is undertaken on the fractionator and furnaces and therefore will be undertaking this planned work during the September [2017] turnaround, extending the turnaround from 24 days to 45 days.

[24] TransCanada did not provide any supporting documentation to verify its calculated daily production levels of 282 000 bbl/d when the plant is fully operational. We noted TransCanada's assumption that CNRL would need to produce 282 000 bbl/day per day in order to compensate for when the plant would undergo a complete shutdown for 41 days a year. We also note that in 2017, CNRL estimated a downtime of 24–45 days to complete both a turnaround and the Horizon 3 expansion. Projects such as the phase 3 expansion are more complex and may prolong turnarounds. We accept that project turnarounds are

necessary and are regularly scheduled, during which production would be halted or significantly reduced. However, TransCanada's estimated annual planned complete downtime of 41 days appears to be excessive in duration and in frequency.

[25] We also considered Fort McKay's assertion that the Horizon plant annual production would be restricted to an annual average of 232 000 bbl/d by its AER authorization. We find that this is not an accurate interpretation of the Horizon plant's AER authorization. The production number referred to in the Horizon plant authorization is a nominal capacity that was used by CNRL to design the Horizon plant. Improvements in technology or process may enable CNRL to produce above that capacity. The AER does not set limits on production of SCO or bitumen that the Horizon plant may produce on a daily or annual basis. The AER regulates environmental emission limits, and the AER expects that facilities will meet their environmental and emission limits regardless of the level of production.

[26] In considering the evidence of both TransCanada and Fort McKay, we did not rely on either Fort McKay's assertion of a 232 000 bbl/d production limit or TransCanada's calculation of 282 000 bbl/d. We relied on CNRL's public materials cited by parties. These materials indicate production levels of 250 000 bbl/d after completion of phase 3 and potential gradual capacity increases after phase 3.

Findings

[27] We conclude that the daily average future capacity of the Horizon plant will exceed 250 000 bbl/d.

Transportation Capacity of the Horizon Pipeline

[28] The parties gave a range of conflicting estimates on the transportation capacity of the Pembina pipeline:

- Fort McKay cited Pembina Pipeline Corporation's public information. This information stated that Pembina Pipeline Corporation constructed and operates a dedicated pipeline to the Horizon plant called the Horizon pipeline. They provided evidence of a 25-year contract between Pembina Pipeline Corporation and CNRL to transport up to 250 000 bbl/d of SCO via the Horizon pipeline (Pembina Pipeline Corporation's news release dated November 9, 2006; attached as appendix 5).
- TransCanada submitted that the White Spruce pipeline project would tie into the Horizon pipeline about 20 km south of CNRL's plant. TransCanada asserted that below the interconnection point, the Horizon pipeline has an annual average capacity of 220 000 bbl/d and a maximum hydraulic capacity of 250 000 bbl/d. TransCanada asserted that the capacity of the Horizon pipeline is constrained below the proposed interconnection point.

[29] We noted that both parties agreed on a 250 000 bbl/d capacity for the Horizon pipeline. We relied on Pembina Pipeline Corporation's public information, cited by Fort McKay. While TransCanada

asserted that the existing system is constrained below the proposed interconnection point, it did not give any evidence in support of this.

Findings

[30] We find that the Horizon pipeline, operated by Pembina, can handle up to 250 000 bbl/d of SCO from the Horizon plant.

Other Means of Transporting Production from the Horizon Plant

[31] Fort McKay suggested the following two options for addressing an increase in SCO from the Horizon plant:

- optimize the Northern Courier Pipeline (currently under construction by TransCanada) to transport SCO directly to other oil sands operations in the region and free up capacity on the Northern Courier line to ship SCO from the Horizon plant or
- use SCO production from the Horizon plant as diluent for bitumen production from other projects in the region.

[32] Implementing these options may require measures beyond the AER’s authority.

[33] TransCanada did not present other options. It maintained that the White Spruce pipeline project could assist the orderly development of the province’s oil and gas resources and that it is the only option available to transport additional SCO to delivery points.

Findings

[34] We find that there are no other viable options to transport increased production from the Horizon plant.

Conclusions

[35] We make the following determinations:

- The daily average future capacity of the Horizon plant will gradually exceed 250 000 bbl/d of SCO once the expansion is complete.
- The Horizon pipeline operated by Pembina can handle up to 250 000 bbl/d of SCO from the Horizon plant.
- There are no other viable options to transport increased production from the Horizon plant.

[36] Given the above we find that the proposed White Spruce Pipeline project is needed to provide for the efficient and orderly development of Alberta’s energy resources and will not result in unnecessary proliferation.

Potential Adverse Effects on Aboriginal Participants

[37] We considered how the project could affect Fort McKay and their ability to exercise their treaty and aboriginal rights. Fort McKay's Treaty 8 and aboriginal rights are constitutionally protected and include their right to hunt, to fish, to trap, and to gather for food, social, cultural, and consumption purposes and to use and enjoy their reserve lands.

[38] As noted, the project would be located within Fort McKay's traditional territory. Fort McKay asked that we consider current extensive development within their traditional territory when considering the project. Their evidence indicated that over twenty large-scale industrial projects are currently operating in the area, including nine oil sands mines, eight in situ oil sands projects, three upgraders, and multiple roads, pipelines, transmission lines, and other land disturbances.

[39] TransCanada did not contest Fort McKay's evidence of existing industrial activity within their traditional territory.

[40] The main pipeline's northern end starts about 6 km from the nearest point on Fort McKay's reserve lands, Indian Reserve (IR) 174D, and 7 km from the Hamlet of Fort McKay. The project's route would be colocated along the routes of other existing linear disturbances and would increase the existing linear footprint. Base plan maps filed by TransCanada in support of the pipeline applications show the presence of at least three pipelines along much of the proposed route and ten pipelines along one portion of this route.

[41] Fort McKay were most concerned about

- watercourse crossings,
- wildlife and habitat,
- herbicide use, and
- cumulative effects of industrial development on exercising their treaty and aboriginal rights.

[42] Other concerns raised included construction, effects on historical resources, and trails and access to traditional land-use areas.

Watercourses

[43] TransCanada's project would cross 31 waterbodies, including crossings at three main watercourses: the Dover River, Mackay River, and an unnamed tributary to the Mackay River. Fort McKay identified these watercourses as being important to their members for travel and the exercise of their rights, including the right to fish. They expressed concern that the crossings would affect water quality and fish due to the potential for bank erosion and leaks.

[44] TransCanada stated that it would use horizontal directional drilling at a minimum depth of 48m below the watercourse bed for the three main watercourse crossings. It said this would mitigate bank erosion and effects on fish habitat at these crossings. For the remaining watercourse crossings, TransCanada would construct open-cut crossings during frozen ground conditions to minimize disturbance.

[45] The use of horizontal directional drilling and the proposed crossing depth will protect the three main watercourses from disturbance to fisheries and habitat. Minimal disturbance techniques, erosion control procedures, and monitoring during and after construction will mitigate potential adverse effects on the remaining watercourse crossings and Fort McKay's rights to use those watercourses.

Findings

[46] We find that the proposed watercourse crossing methods will avoid or minimize impacts to Fort McKay's rights to fish, travel, and use the waterbodies for cultural enjoyment.

Wildlife and Their Habitat

[47] Fort McKay expressed concerns about the project's impacts on wildlife in the area. They were primarily concerned about the impacts on exercise of their treaty and aboriginal rights focused on caribou and moose.

[48] Fort McKay stated that caribou are a cultural keystone species. Caribou used to be a regular part of their seasonal hunting rotation. They are valued for meat, hides, and implements that are made from the caribou. However, their members now refrain from hunting caribou because of concerns about the low population, which they maintain is due to industrial development. They expressed a desire to harvest caribou as well as being able to share the traditional knowledge about caribou with future generations.

[49] Moose are the species Fort McKay most heavily consume. They were concerned that the project would disturb critical moose habitat and widen the linear disturbance, creating greater access for predators such as wolves.

[50] TransCanada's caribou protection plan sets out mitigation strategies to reduce effects of the project on caribou and caribou habitat. In addition to the plan, it indicated that general mitigation measures in its environmental protection plan for the project would minimize impacts to all wildlife, including caribou and moose. These include

- paralleling existing linear disturbance for the entire project footprint,
- completing construction during winter conditions, and
- using minimal surface disturbance techniques to facilitate quicker vegetation recovery.

[51] The environmental protection plan also includes a Wildlife Species of Concern Discovery Contingency Plan that addresses situations where previously unidentified sensitive wildlife species or site-specific habitats are encountered during construction. Actions in response could include narrowing the proposed area of disturbance, protecting the site using fencing and signage, and changing or delaying construction activities to avoid sensory disturbance. TransCanada indicated that it would have environmental inspectors on the project site to carry out preconstruction wildlife reconnaissance and ensure that both protection plans are implemented during construction.

[52] TransCanada's environmental protection plan does not specifically mention moose, so Fort McKay suggested some moose-specific mitigation measures to reduce the effects on moose habitat and movement and to avoid disturbing them during late pregnancy and other vulnerable times. TransCanada recognized the significance of moose to Fort McKay and committed to adding a requirement to its environmental protection plan that project construction be suspended when moose are present on or near the project right-of-way and only resumed once the moose have safely moved from the area. TransCanada also indicated that it would take measures to provide exit ramps in trenches open for more than two days and provide a means of crossing the project footprint at identifiable wildlife migration or travel corridors. Fort McKay acknowledged that these new measures would be beneficial for caribou, moose, and other wildlife in the project area.

[53] We have considered the mitigations proposed in TransCanada's caribou and environmental protection plans. These address various potential effects on wildlife in the vicinity of the project, especially during construction. They have been previously reviewed and accepted by the AER and are generally consistent with regulatory guidance and industry practice. Constructing the project during the winter (frozen conditions) and minimizing the overall permanent footprint of the project and resultant vegetation removal as outlined in the environmental protection plan will minimize the longer-term effects of the project.

Findings

[54] We acknowledge the importance of both caribou and moose to Fort McKay. We considered the concerns raised by Fort McKay and reviewed the mitigation measures proposed by TransCanada. Having considered TransCanada's caribou and environmental protection plans, along with conditions we have imposed, we find that Fort McKay's wildlife concerns have been addressed and that any incremental effects of the project on Fort McKay's rights to harvest wildlife will be adequately mitigated.

Conditions of Approval

[55] During this hearing, TransCanada made additional commitments to wildlife protection measures. We impose the following conditions:

- If moose are identified in the immediate vicinity (right-of-way plus 100 metres) of the construction zone, TransCanada must immediately suspend work in the vicinity of the moose, assess the situation, and allow construction to resume only when the moose have moved safely away from the construction zone.
- If a trench must be left open overnight or unattended, sloped subsoil ramps must be placed at the ends of the open trench to create egress for wildlife that might enter the trench.
- At wildlife migration or travel corridors identified by TransCanada or the AER, TransCanada must install breaks in windrows to allow wildlife movement across the project footprint.

Herbicide Use

[56] During operations, pipeline operators commonly use herbicides to control vegetation growth along the right-of-way.

[57] Fort McKay raised concerns about herbicide use and its effects on their exercise of treaty and aboriginal rights. Fort McKay's evidence indicated that herbicide use would deter their members from exercising their rights. They stated that a pristine and natural landscape is required to be able to harvest plants and animals for food and to use them for spiritual, cultural, and medicinal purposes. Herbicides are seen as poisonous to traditional plant medicines and to food consumed by wildlife and as a threat to human health. Fort McKay stated that their members seek assurance that they are not at risk from herbicide use; otherwise, they will avoid harvesting or other traditional activities on industrially disturbed lands.

[58] TransCanada has committed to restricting the general application of herbicides on a site-specific basis near discrete traditional land-use sites, as agreed upon with the affected aboriginal community. To do so, it would require assistance from the community in identifying such sites on or adjacent to the project footprint. It set out a number of alternate vegetation control methods it could use near these sites. These include spot spraying, wicking, mowing, or hand picking.

[59] Fort McKay has indicated that they cannot provide locations for project-relevant traditional land-use sites without a traditional land-use study for this project. They stated they would be willing to work with TransCanada to identify traditional land-use sites if they could be satisfied that TransCanada would seriously consider the information provided from Fort McKay's perspective and commit to funding a traditional land-use study and community engagement to gather the necessary information.

[60] TransCanada's position was that a traditional land-use study is not required. Its view was that the project's route and effects on Fort McKay's rights have been examined through consultation, a helicopter flyover and map review, and studies carried out for previous development of the Northern Courier and McKay East pipelines.

[61] It appears to us that the main point of disagreement about TransCanada's commitment is the identification of specific traditional land-use sites. We note that while a traditional land-use study can be an important source of information where resource development is proposed, it is not statutorily required for applications under the *Pipeline Act* or *Public Lands Act*. We also note references in Fort McKay's evidence to the Fort McKay community database. Fort McKay's traditional land-use expert stated that this database represents the most accurate recorded data available for the community's land use. According to that expert, this database is the source of Fort McKay's evidence on numbers of traditional land-use sites intersected by and within proximity of the project. Fort McKay further confirmed its reliance upon those numbers in response to AER questions.

Findings

[62] Given the description of this database and Fort McKay's reliance on it for other parts of their evidence on traditional land-use sites, we believe that Fort McKay has sufficient information at hand to provide specific traditional land-use site information to TransCanada. We will not direct TransCanada to fund a traditional land-use study for this project.

[63] We find that TransCanada's commitment to restrict general application of herbicides near traditional land-use sites (that may be provided by Fort McKay), together with its more general mitigation measures on herbicide use set out in its environmental protection plan, represents a responsible approach to avoiding potential impacts to Fort McKay's exercise of its treaty and aboriginal rights.

Cumulative Effects on Treaty and Aboriginal Rights

[64] As noted above, Fort McKay's traditional territory is the site of extensive industrial development. They consider their culture and identity integrally linked to the landscape because it is rooted in a traditional bush-based economy. Fort McKay asserted that this project, in combination with other industrial development in its traditional territory, would result in adverse cumulative effects on their treaty and aboriginal rights. They submitted that the cumulative effects on their rights include

- reduction of the area where they can exercise their treaty and aboriginal rights in a culturally relevant way due to their avoidance of traditional land-use activities in areas affected by industrial development;
- negative effects on food and resource gathering;
- reduced connection to community, history, and knowledge about traditional land use;
- reduced enjoyment of traditional land-use activities;
- concerns about potential health and safety risks; and
- uncertainty about their ability to access their reserve lands and traditional territory.

[65] TransCanada does not dispute Fort McKay's evidence on the presence and effects of industrial development within Fort McKay's traditional territory. Its position is that colocating the project route with existing pipelines, together with mitigation measures in its environmental protection plan, would minimize environmental disturbance and limit the impacts on Fort McKay.

[66] Fort McKay asked us to consider *Decision 2013 ABAER 011: Shell Canada Energy, Jackpine Mine Expansion Project* and the Fort McKay–specific assessment study submitted in that proceeding. The decision referred to the study's assessment of industrial development impacts on Fort McKay's cultural heritage, and the joint review panel found that there were cumulative adverse effects on some elements of Fort McKay's cultural heritage. Fort McKay also referred to the 2015 review panel report on the *Lower Athabasca Regional Plan* (*LARP*), which considered whether *LARP* adversely affected Fort McKay's rights and concluded that cumulative effects were not being properly managed in the Lower Athabasca region.

[67] TransCanada suggested that we should not consider the Jackpine mine expansion decision and the Fort McKay–specific assessment study due to

- the much larger size and scale of the Jackpine mine expansion,
- comments in that decision by the joint review panel noting that some of Fort McKay's cumulative effects concerns were too broad, and
- Fort McKay's resolution of its project-specific concerns and withdrawal from that hearing before its completion.

[68] In relation to the *LARP* review panel report, TransCanada argued that our obligation is to act in accordance with *LARP* and that we are not able to assess whether *LARP* is accomplishing its cumulative effects objective.

[69] We note that we are required under section 20 of *REDA* to act in accordance with any applicable *Alberta Land Stewardship Act* regional plan, which for this project is *LARP*. While *LARP* is Alberta's vehicle to address cumulative effects in the Lower Athabasca region, it does not currently set any specific limits or thresholds related to the cumulative effects of development on aboriginal rights. Nor did either party point us to any other legislative or regulatory limits for cumulative impacts on aboriginal rights. We do not find Fort McKay's reference to the *LARP* review panel report of assistance, as it does not provide any guidance on this issue.

[70] There was a lack of evidence on how cumulative effects of the project will specifically affect Fort McKay's treaty and aboriginal rights. We do not find either the Jackpine mine expansion decision or the reference to the Fort McKay–specific assessment useful. Fort McKay has not made clear to us whether the joint review panel's finding of cumulative effects on some elements of their cultural heritage relates to any of the particular concerns they have raised about this project. Because they have not provided us with

the Fort McKay–specific assessment study relied upon by the joint review panel, we cannot make a sound comparison of cumulative effects assessed in the context of the Jackpine mine expansion project with potential impacts of this project.

Findings

[71] We find that concerns about cumulative effects on treaty and aboriginal rights raised by Fort McKay are general in nature and not supported by evidence specific enough to allow us to make direct findings of impact or give meaningful direction to eliminate or mitigate such alleged effects.

[72] We note that *LARP* sets out plans to develop a biodiversity management framework and regional landscape management plan for public land in the Green Area within the region. *LARP* indicates that these frameworks will consider how the region's aboriginal peoples can continue to exercise their constitutionally protected rights within reasonable distances of the main population centres. Neither of these frameworks are yet completed or in effect. When complete, such frameworks should provide clearer direction and guidance to the AER in determining issues like those raised by Fort McKay in this hearing.

[73] The ACO also indicated that the Government of Alberta (GoA) is working through *LARP* to respond to cumulative impact concerns. The panel encourages the GoA to complete and put into effect a biodiversity management framework and a regional landscape plan for the Lower Athabasca region.

Construction

[74] Fort McKay presented evidence on the potential effects of the construction on their rights. Their concerns included

- clearing activities and construction noise that would displace animals (creating added cost, travel, and time for members to go on the land to harvest these animals), and
- reduction, delay, or cancellation of traditional land-use activities in areas of pipeline development because usual routes of safe passage may be obstructed or blocked by construction activities.

[75] TransCanada indicated that the right-of-way area is already disturbed. Its position was that any impacts to traditional land use from construction would be short term, temporary, limited to the right-of-way width, and able to be mitigated. TransCanada committed to provide the proposed construction schedule and maps to aboriginal communities before construction. It acknowledged that there may be temporary effects on traditional access during construction for safety reasons, which would require coordination with its construction personnel to ensure safe access. It stated that traditional users would not be restricted from accessing the project area where there was no active construction or other identified safety risk such as open trenches. TransCanada asserted that Fort McKay's access and land use would be the same upon completion of project construction as is currently experienced.

[76] In considering Fort McKay's evidence about wildlife dispersion due to construction, we note provisions in TransCanada's environmental protection plan to identify and reduce impacts on caribou and its commitment to apply similar measures to moose. We discuss these more fully in the wildlife section of this decision. TransCanada's commitment to provide Fort McKay with its proposed construction schedule and maps before construction should offer a means for Fort McKay members to plan safe passage and travel during the construction period.

Findings

[77] We find that the time-limited nature of project construction and TransCanada's proposed mitigation measures together adequately mitigate construction impacts to Fort McKay's rights.

Traditional Trails

[78] Fort McKay had concerns about how the project would affect trails used throughout their traditional territory, particularly the trail network used to access the Moose Lake area. Fort McKay's expert witness indicated that the majority of traditional land-use sites intersected by the project footprint are trails to other traditional land-use sites. The trails that access the Moose Lake Reserves, located approximately 60 km northwest of the Hamlet of Fort McKay, are of particular concern to Fort McKay. Fort McKay members value the Moose Lake Reserves as being relatively pristine and a refuge from industrial development. Fort McKay's evidence discussed Fort McKay's desire to protect all Moose Lake access trails through the negotiation of a Moose Lake access management plan with the Alberta government. Pending the completion of such a plan, Fort McKay proposed a five kilometre buffer around the trails.

[79] TransCanada's environmental protection plan has specific mitigation measures for trails, including clear marking, gaps in windrows to align with identified trails, and open access by traditional users to the project area where there would not be any active construction or open excavations. TransCanada would give Fort McKay the proposed construction schedule and maps before construction. All construction activity would be restricted to the approved right-of-way and related locations. TransCanada committed to bore underneath an identified access route crossed by the project footprint to avoid any travel restrictions along that road. TransCanada disagreed with the five kilometre buffer for the Moose Lake trails, indicating that Fort McKay is unwilling to disclose the trails' footprints. This prevents it from proposing specific mitigation.

[80] Both parties' evidence indicates that the project's impacts on trails will occur during clearing and construction. While Fort McKay's evidence states that it is not possible to identify all variations of the Moose Lake trail network, we believe that TransCanada's commitment to provide the proposed construction schedule and maps before construction will provide a means for Fort McKay users of those various trails to plan safe passage and travel during the construction period. Maps provided by Fort McKay show a small portion of the project route intersecting with a limited amount of the area they indicate as having high traditional transportation trail values.

Findings

[81] We find that the time-limited nature of project construction and TransCanada's proposed mitigation measures combine to adequately mitigate impacts to trails used by Fort McKay.

Historical Resources

[82] TransCanada's environmental protection plan sets out training requirements for project environmental inspectors and contingency plans for heritage resource and traditional land-use site discovery. Its evidence includes details of the archeological aspects of this training (uncontested by Fort McKay). All project employees and contractors would undergo a preconstruction orientation that includes a review of the plan. TransCanada also invited Fort McKay's archeologist to attend the orientation session.

[83] Fort McKay was concerned that TransCanada would only train project environmental inspectors on recognizing sites of historical or traditional-use significance. Fort McKay asserted that construction personnel should also receive this training.

[84] We note that TransCanada's environmental protection plan sets out processes for identifying and protecting historical resources and traditional land-use sites. However, in considering Fort McKay's evidence, it appears that there may be a gap in the protection of potential historical resources or traditional land-use sites if construction personnel do not learn about characteristics of such sites.

Findings

[85] We find that proposed training, contingency plans for historical resources and traditional land-use sites, and the condition we are imposing, adequately mitigate any potential adverse impacts on historical resources.

Condition of Approval

[86] Given TransCanada's submissions regarding archeologist involvement in personnel orientation, we make it a condition that TransCanada must use a qualified archeologist to provide training in the environmental orientation program to construction personnel on recognizing potential historical resource and traditional land-use sites.

Aboriginal Consultation Office Reports and Recommendations

[87] The Alberta government is required to consult with aboriginal groups when energy decisions under its jurisdiction may adversely affect treaty and aboriginal rights. The AER is an independent body created through *REDA* to regulate energy development in Alberta, including pipelines. Under section 21 of *REDA*, the AER has no jurisdiction to assess the adequacy of Crown consultation associated with the rights of aboriginal people. This authority remains with the Alberta government and is carried out by the

ACO. The Alberta government has directed that AER processes are part of Alberta's overall aboriginal consultation process as appropriate.

[88] Under the *Aboriginal Consultation Direction*, Energy Ministerial Order 105/2014, and Environment and Sustainable Resource Development Ministerial Order 53/2014, the AER cannot make a decision on an energy application requiring aboriginal consultation until it has requested and received the ACO's advice on consultation adequacy and on any required action to address potential adverse effects on treaty and aboriginal rights or traditional uses. The ACO usually provides this advice through a project-specific report to the AER. Where the AER holds a hearing on a project, the ACO may provide a second report to address any impacts raised in the hearing that were not previously addressed in the consultation process.

[89] We considered reports from the ACO and their recommendations. The ACO made two consultation reports about this project:

- the first, dated March 17, 2017, addressed the project consultation and potential adverse impacts on Fort McKay's treaty and aboriginal rights;
- the second, dated November 16, 2017, took into account the evidence filed and arguments made in this hearing and dealt with matters that were not previously addressed in the consultation process.

[90] The ACO found consultation with Fort McKay to be adequate. The ACO recommended the need to

- reduce impact to moose,
- reduce impact to caribou habitat,
- protect wildlife from open trenches during construction, and
- carry out on-site wildlife assessments before construction.

[91] The ACO recommended that the AER require actions consistent with or equally effective as TransCanada's mitigation plans to address these impacts. We considered this recommendation and imposed conditions on TransCanada. In combination with these conditions, we find that TransCanada's proposed mitigation measures will address the potential adverse impacts as identified by the ACO.

[92] The two reports also identified several other areas of concern to Fort McKay. However, the ACO found TransCanada's proposed avoidance and mitigation measures reasonably responsive to these concerns and so did not make any specific recommendations to address them. These concerns are

- protection of aquatic resources at the three main watercourse crossings on the Dover and Mackay Rivers and an unnamed tributary to the Mackay River,
- impact to fish and fish habitat for 31 proposed watercourse crossings,
- impact to traditional land use and trapping,

- access hindrance and competition,
- impact to wildlife and habitat, and
- impact to vegetation, including harvesting, wetlands, and effects of vegetation control.

[93] We considered these concerns and both parties' evidence and find TransCanada's proposed avoidance and mitigation measures, along with the conditions we have imposed, will adequately mitigate potential adverse impacts on Fort McKay's treaty and aboriginal rights.

[94] The ACO's reports also identified Fort McKay concerns that the ACO characterized as being general in nature and best addressed outside of a project-specific consultation. The ACO indicated that it would seek to advise appropriate Alberta ministries of these broad concerns. These concerns are

- maintaining environmental integrity;
- cumulative impact to traditional land use;
- requests for information about the implications of potential spills or leaks, response plans, and notification plans; and
- restoration of traditional territory used for industrial development.

[95] The ACO noted that Alberta is dealing with general cumulative impact issues through implementation of *LARP*. We have touched on cumulative impacts in relation to treaty and aboriginal rights, as discussed above.

Potential Environmental Effects

[96] The AER reviewed TransCanada's construction plan and its mitigation measures for the White Spruce pipeline project before the hearing to ensure compliance. TransCanada also has an environmental protection plan, which sets out project-specific issues and environmental protection measures for features it has identified on or near the proposed pipeline right-of-way. The plan outlines location-specific mitigation measures for wildlife, traditional land-use areas, wetlands, watercourse crossings, and rare plants.

[97] The White Spruce pipeline project has the potential to affect various environmental features in the area in which it is proposed. The following environmental factors were issues raised during this hearing:

- Key Wildlife and Biodiversity Zones,
- creek and river crossings,
- wetlands,
- the West Side Athabasca (caribou) Range, and
- pipeline routing and width of the right-of-way.

Key Wildlife and Biodiversity Zones

[98] TransCanada's project would be located within a designated Key Wildlife and Biodiversity Zone associated with the Mackay River for about 0.8 km. Key Wildlife and Biodiversity Zones are identified and mapped by the Alberta government. They are typically found along major river valleys because of the topographic variation and conditions that support good winter browsing and increased levels of biodiversity.

[99] TransCanada plans to use horizontal directional drilling to bore beneath the Mackay River and the associated biodiversity zone. This method of crossing does not disturb the surface and mitigates any physical disturbance or risks to the zone at this location.

Findings

[100] We find that the use of horizontal directional drilling techniques to install the pipeline beneath the Mackay River biodiversity zone will adequately mitigate construction and long-term effects on the Key Wildlife and Biodiversity Zone.

Creek and River Crossings

[101] The White Spruce pipeline project would cross 31 watercourses including the Dover River and the Mackay River and one unnamed tributary to the Mackay River. These rivers are important to Fort McKay for fish harvesting purposes. Fort McKay was concerned about how a watercourse crossing of these rivers could affect fish and fish habitat.

[102] TransCanada noted that a qualified aquatic environmental specialist had completed a watercourse assessment for the project and proposed watercourse crossing techniques and mitigations. The specialist confirmed that the methods it recommended for crossings are not expected to result in harm to fish or fish habitat. Mitigations included

- construction primarily under frozen conditions,
- horizontal directional drilling for the Dover and Mackay Rivers and a tributary to the Mackay River with a minimum depth of cover of 48 m below these watercourse beds, and
- open-cut crossings for smaller watercourses during frozen ground conditions to minimize disturbance.

[103] Fort McKay noted a preference for drilled crossing methods for all fish-bearing watercourses and drainages. TransCanada stated that all proposed stream and creek crossings comply with the GoA's *Code of Practice for Pipelines and Telecommunication Lines Crossing a Water Body*, *Code of Practice for Watercourse Crossings*, and Canada's Department of Fisheries and Oceans *Measures to Avoid Causing Harm to Fish and Fish Habitat*.

[104] TransCanada's plan to use horizontal directional drilling to cross the three main watercourses will minimize risks to the most important fish-bearing rivers in the area.

[105] We considered evidence presented by TransCanada about the use of a qualified aquatic environmental specialist and compliance with existing regulatory requirements and guidelines in the design of creek and river crossing plans. It indicated these steps will minimize the risk of direct impacts to fish as well as minimize the risk of runoff, erosion, and sedimentation from activities adjacent to all proposed stream crossings.

Findings

[106] We find that the creek crossing requirements and fish protection measures identified by TransCanada's specialist, compliance with the GoA and Department of Fisheries and Oceans requirements, and specific mitigation measures set out in TransCanada's environmental protection plan will mitigate construction impacts and long-term risks to fish and fish habitat from the project.

Wetlands

[107] Areas of muskeg and wet areas (fens, bogs) are located throughout the proposed development according to TransCanada. Fort MacKay was concerned the project would result in the loss of traditionally important wetlands.

[108] TransCanada noted that it routed the project parallel to existing disturbances to minimize disturbance to wetlands. Other measures noted by TransCanada to reduce effects on wetland areas included

- reducing the removal of vegetation in wetlands,
- conducting construction under frozen conditions,
- reducing grading within wetland boundaries, and
- using natural recovery methods of reclamation.

[109] TransCanada's wetland crossings would comply with the GoA's *Code of Practice for Pipelines and Telecommunication Lines Crossing a Water Body*. Site-specific mitigation measures for wetlands are outlined in TransCanada's environmental protection plan.

[110] Fort Mackay did not give any specific evidence to support their view that long-term effects to wetlands in the area would occur.

[111] We considered the mitigation measures as set out in TransCanada's environmental protection plan and the compliance requirements of the *Code of Practice for Pipelines and Telecommunication Lines Crossing a Water Body*. We note that the AER has a comprehensive and well-established regulatory process for regulating the environmental risks of pipeline crossings of wetlands and that TransCanada's

mitigation measures set out in its environmental protection plan are consistent with regulatory guidance and industry practices. We also note that these wetland crossings are adjacent to existing linear disturbances.

Findings

[112] We find TransCanada's proposed mitigation plans, particularly its plan to construct the project under frozen conditions, will minimize the risk of long-term effects to wetlands in the project area. We also confirm that its proposed mitigation plans are in compliance with AER requirements.

Condition of Approval

[113] Given the above, construction must be conducted only under frozen conditions.

West Side Athabasca Range

[114] The southernmost 12.6 km of TransCanada's project would be located within lands provincially identified as caribou range and designated federally as critical habitat for the West Side Athabasca River caribou herd. This herd is included within the boreal populations of woodland caribou designated as threatened under the federal *Species at Risk Act* and the Alberta *Wildlife Act*.

[115] According to Environment Canada 2012 data submitted by both parties on the West Side Athabasca River caribou herd, 68–69 per cent of total caribou habitat within the range was disturbed, leaving only 31–32 per cent undisturbed habitat. The range is well below the minimum threshold of 65 per cent undisturbed habitat established by the *Recovery Strategy for the Woodland Caribou (*Rangifer tarandus caribou*), Boreal Population, in Canada*. The herd's population that same year was estimated by Environment Canada as being between 201 and 272 caribou (from Fort McKay's wildlife report, undisputed by TransCanada). Such a level is not considered self-sustaining. Protection of critical caribou habitat in the West Side Athabasca Range is a significant concern.

[116] TransCanada identified various measures to mitigate effects on caribou habitat in its caribou and environmental protection plans. The project right-of-way would parallel existing linear disturbance for its entire length. Fort McKay's wildlife expert acknowledged that paralleling existing disturbance will reduce the area of habitat impact but argued that it will contribute to cumulative effects.

[117] TransCanada estimated that the project would impact about 31 hectares of land within the West Side Athabasca Range, of which approximately 9 hectares was already disturbed. The parties disagreed on the significance of this disturbance to the range. TransCanada's position was that the caribou protection plan and general mitigation measures for wildlife impacts in the environmental protection plan would mitigate the effect of the project on caribou in the West Side Athabasca Range and the entire project area. Fort McKay argued that the project effectively eliminates the disturbed area as caribou habitat and thus does not protect critical caribou habitat.

[118] TransCanada said it would conduct construction activities under frozen conditions, which minimizes soil and vegetation disturbance, and use natural revegetation techniques to minimize caribou habitat disturbance. Such techniques would work to maintain the root layer's integrity along the right-of-way and help disturbed vegetation recover faster. These techniques are detailed in its environmental and caribou protection plans and are consistent with regulatory guidance.

[119] TransCanada would limit control of regenerating natural vegetation within the range during project operations within five metres on either side of the project's centreline. TransCanada suggested that this measure would contribute to habitat regeneration within the range and future attainment of the federal caribou recovery strategy's minimum threshold of sixty-five per cent undisturbed habitat.

[120] Fort McKay argued that the West Side Athabasca River caribou herd's rate of population decline is rapid enough that these measures would not effectively protect critical habitat or caribou populations.

[121] The Alberta government has restrictions on construction activity within caribou ranges from February 15 to July 15 to reduce impacts to pregnant cows and their calves. TransCanada would use an early in, early out approach to complete the majority of project activity in the West Side Athabasca Range before February 15 and limit late-winter activities. However, it also indicated that if a decision approving the project were to be issued later than November 10, 2017, its schedule may be delayed and construction activity may be required within the West Side Athabasca Range during the restricted activity period.

[122] TransCanada's environmental protection plan includes a Wildlife Species of Concern Discovery Contingency Plan that address situations where previously unidentified sensitive wildlife species or site-specific habitats are encountered during construction. It prescribes a range of actions to avoid or mitigate impacts. Environmental inspectors would be on site to carry out preconstruction wildlife reconnaissance and ensure that the environmental and caribou protection plans are implemented during construction.

[123] Fort McKay's wildlife expert recommended that the project not be approved until Alberta's caribou range plans are complete and the AER determines whether the project meets requirements in federal and provincial caribou recovery plans. Federal and Alberta requirements for caribou protection are currently in a state of transition.

[124] Fort McKay's evidence recommended that the AER and TransCanada carry out an exhaustive review of possible construction options in relation to critical caribou habitat. Their wildlife report also recommended that TransCanada conduct a cumulative effects assessment of the project before it could be approved.

[125] We considered whether this application incrementally adds to the habitat disturbance to an extent that renders the impact unacceptable and immitigable. As stated at the beginning of the environmental section, the AER has reviewed TransCanada's construction plan and its environmental mitigation measures before the hearing to ensure compliance with all AER regulatory requirements.

[126] Currently, no federal or provincial legislated restrictions or moratoria exist on development within the West Side Athabasca Range. We must apply regulation and guidance in effect at the time of this hearing. We believe that it is neither fair nor sound to hold this application in abeyance until the Alberta and federal governments provide new range plans, recovery plans, or other direction.

[127] We note that roughly one-third (9 hectares) of the anticipated 31 hectares of disturbance this project would create within the West Side Athabasca Range would not require new clearing. Fort McKay did not contest this evidence. We consider this an indication of responsible construction planning and impact mitigation by TransCanada.

[128] Our decision however was not issued within the timelines that TransCanada requested. As a result, it may have to alter its schedule in such a way it may need to carry out construction activity within the West Side Athabasca Range during the restricted activity period. We note that authorization for construction within the restricted activity period requires approval from the AER. We are confident that the AER will address any such requests in a manner that provides appropriate protection for the West Side Athabasca River caribou herd.

[129] We note the importance of winter construction to TransCanada's mitigation measures, both in enabling minimal surface disturbance construction and reducing impacts to pregnant cows and their calves.

Findings

[130] Fort McKay requested that an additional review of possible construction options in relation to caribou habitat be conducted. It is our view that such a review is not necessary and would not add to meaningful oversight of this project. We will not require such a review to be undertaken. Fort McKay also requested that a cumulative effects assessment be completed for the project. We believe that such an assessment would be best conducted under the purview of *LARP* as it is the proper vehicle for addressing regional cumulative effects. As such, we will not require an additional cumulative assessment to be completed before making our decision on this project.

[131] We find that the proposed vegetation control limitation within the range will not provide as much benefit as TransCanada suggests. Vegetation control within 5 m on either side of the pipeline's centreline for a 15 m right-of-way leaves a revegetated strip of 2.5 m on either side of the right-of-way. Of itself, this will not make a significant contribution to restoration of critical habitat within the West Side Athabasca Range, particularly given the lengthy timeline for regeneration to mature forest. As set out in the condition below, we require TransCanada to prepare and implement habitat restoration in the West Side Athabasca Range to offset the effects of the project.

[132] We find that the mitigation measures in TransCanada's environmental and caribou protection plans, together with the conditions we have imposed, will minimize both the short- and long-term effects on

caribou and caribou habitat. The project will not add to the long-term caribou habitat disturbance to an extent that renders the impact unacceptable and immitigable if these measures and conditions are met.

Conditions of Approval

[133] We recognize the importance of protecting, maintaining, and, where appropriate, restoring critical habitat for caribou. We also note that TransCanada has established a plan for protecting caribou, which it maintains will minimize the effects on the West Side Athabasca Range. We recognize that this plan meets the current requirements of the AER. However, we note that even with best efforts, the project will still disturb approximately nine hectares of previously disturbed area and 22 hectares of new cut habitat within the West Side Athabasca Range.

- Therefore, we require that TransCanada must prepare and submit a caribou habitat restoration plan to the AER for approval for PLA160532 and PLA160531. This plan must have the effect of restoring 2.0 times the area of new cut habitat affected in the West Side Athabasca Range by the project. The goal or outcome of the plan is to ensure that there is, at a minimum, no net loss of caribou habitat from the project in the West Side Athabasca Range. The restoration plan must be filed at least six months before operations for the White Spruce pipeline project begin and approved by the AER before operations start up. In addition to any measures that TransCanada determines should be included, the restoration plan must include
  - a list of specific restoration sites in the West Side Athabasca Range identified for restoration, including their location, area, description and site-specific restoration plans;
  - specification drawings for implementation of restoration methods at each site;
  - a quantitative and qualitative assessment of the total area of caribou habitat that will be restored and how these restoration sites are equivalent to the 2.0 times the new cut area disturbed by the White Spruce pipeline project within the West Side Athabasca Range;
  - a schedule indicating when restoration measures will be initiated and completed;
  - a process and timeline for completing an assessment of the effectiveness and value of the restoration plan; and
  - a summary of TransCanada’s discussions with Fort McKay about the restoration plan, including any concerns that Fort McKay raised and how or if these concerns were addressed.

Pipeline Routing and Width of the Right-of-Way

[134] Paralleling existing disturbances meets the principles of integrated land management as established by the GoA and AER regulatory guidance. Routing a pipeline along a route that has already been disturbed minimizes the environmental effects of the project. TransCanada selected a route that parallels existing linear disturbances for nearly all of its 71.5 km length. One minor exception is an approximately

680 m section of the right-of-way that would not parallel the adjacent corridor because the pipeline would have to skirt around an existing well site. The remainder of the proposed right-of-way would be entirely adjacent to or within existing surface dispositions. This routing approach enables TransCanada to

- be consistent with industry best practices, GoA integrated land management requirements, and AER regulatory guidance;
- reduce its overall footprint by using working space on adjacent rights-of-way and minimize its permanent right-of-way requirement to 15 m in width;
- address concerns of indigenous peoples;
- minimize the project footprint on vegetation and wildlife, and
- reduce potential habitat fragmentation.

[135] Fort McKay submitted that colocating the project with existing linear disturbances would widen the existing corridor, which currently contains a number of existing pipelines. They stated that by including the White Spruce pipeline project, the right-of-way would span up to 200 m once construction was complete. They argued that increasing the width of the existing corridor would increase hunting pressure from humans and predators.

[136] TransCanada said that because its pipeline route is within or adjacent to or on existing linear disturbance for nearly 100 per cent of the route, it has reduced the width of its permanent right-of-way.

[137] We recognize that the AER does not have regulatory requirements or standards that specify or give guidance on the appropriate width of rights-of-way for pipelines. The AER however expects companies to construct a pipeline in ways that minimize a right-of-way's requirements and disturbance, such as using working space on adjacent linear facilities or minimizing the project footprint by using existing disturbed areas. In turn, doing so also minimizes the effects of a given pipeline project on the environment.

[138] It became obvious to us in submissions made during the hearing that TransCanada planned construction activities so as to minimize new disturbance and to minimize the need for permanent right-of-way requirements and that these activities are in line with what the AER expects.

[139] To determine whether the existing corridors would be widened as Fort McKay claimed, we examined TransCanada's alignment sheets and mapping materials. We confirmed that the existing corridors would be widened by the White Spruce pipeline. However, the addition of the pipeline would not widen the total corridor to 200 m in all locations along the right-of-way. The corridor width would vary depending on the specific existing dispositions that the project parallels along its route. There are sections where the corridor would reach about 200 m, but they are rare. The width of the corridor with the addition of the project would be between 100 and 150 m, often less.

Findings

[140] We accept TransCanada's need for a 15 m permanent right-of-way and find that its plan minimizes the project footprint and reflects a responsible approach to development of the White Spruce pipeline project. Although Fort McKay suggested that an aboveground pipeline be considered as an alternative to the proposed buried pipeline so as to reduce the width of the right-of-way, we did not find their evidence for an aboveground installation to be compelling with regards to reducing the environmental effects of the pipeline.

[141] We accept TransCanada's proposed use of temporary workspace for construction and find that its plan minimizes the project footprint and is a responsible approach to developing the White Spruce pipeline project.

[142] We find that the proposed route and the 15 m proposed width of the right-of-way will minimize the environmental footprint of the project and therefore reduce the long-term disturbance effects of the project. This approach is consistent with the responsible development of Alberta hydrocarbon resources.

Pipeline Design, Construction, and Operation

[143] We reviewed how TransCanada designed and would construct and operate the project. Pipelines need to be constructed and operated safely, and we have legislation, regulations, and standards in place in Alberta to ensure that this is so. AER-regulated pipelines must comply with the *Pipeline Act* and *Pipeline Rules*. Under these, oil and gas pipelines must be designed, constructed, and operated in compliance with Canadian Standards Association (CSA) standards. Applicants must confirm that the pipeline meets these requirements in its application to the AER.

[144] TransCanada confirmed that it would comply with the *Pipeline Act*, the *Pipeline Rules*, *CSA Z662-15*, AER *Directive 056*, AER *Directive 077: Pipelines—Requirements and Reference Tools*, and AER *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*.

[145] The AER completed a technical review of the audit package for the project, which confirmed compliance with regulations and standards. This review by AER technical and authorizations staff convinced us that the technical specifications required by the AER and CSA are being adhered to by TransCanada. The review covered the following topics:

- pipe material compatible with the pipeline contents and CSA code,
- acceptable stress levels,
- suitable maximum operating pressures,
- adequate tie-in points,

- sufficient corrosion mitigations, and
- adequate leak detection.

[146] We assessed the following specific issues for the project:

- pipeline throughput,
- depth of burial,
- safety management system,
- number and placement of isolation valves, and
- emergency response planning.

Pipeline Throughput

[147] Fort McKay requested that the throughput of the project be limited to 120 000 bbl/d because they were concerned about greater spill volumes and other associated risks. Fort McKay did not present evidence to substantiate that limiting throughput reduces the risk or significance of a pipeline release.

[148] TransCanada argued that there is no evidence that a 120 000 bbl/d limit reduces risks associated with the pipeline. It argued further that such a limit would result in a greater proliferation of pipeline facilities.

[149] We considered Fort McKay's submission on limiting the project throughput to 120 000 bbl/d. There was not sufficient evidence to evaluate any correlation between throughput and spill volumes. Should the production of the Horizon plant increase beyond the combined capacity of the Horizon pipeline and the proposed capacity of White Spruce pipeline project, additional transportation will be required. This could result in future proliferation.

Findings

[150] We find that limiting the pipeline throughput to 120 000 bbl/d is not required.

Depth of Burial

[151] Increasing the depth a pipeline is buried at water crossings reduces the risk of damage to the pipeline from hydrological events, such as storms, and therefore reduces the risk of an uncontrolled release. One of the parameters used to calculate the depth of burial is the maximum rainfall from a major rainfall event. The governing standards and rules require the largest historic flood event in 100 years to be used for calculating a pipeline's depth of burial. The same standards require a minimum depth of burial of 0.8 m for a pipeline right-of-way and 1.2 m for pipeline watercourse crossings for low-vapour-pressure pipelines.

[152] Fort McKay raised concerns about increased risk of hydrological events due to the recent Fort McMurray fires and increasing extreme weather events. It argued that TransCanada should base its depth of burial calculations on a 200-year flood event and the associated effects on river bed scouring (removal of soil material beneath which the pipeline is buried) in response to this increased risk. Fort McKay argued that this would reduce the likelihood of impacts on pipelines resulting in pipeline failure.

[153] Fort McKay didn't provide a depth of burial calculation resulting from using a 200-year flood event or whether this would result in a greater depth of burial than that proposed by TransCanada. Nor did they provide any analysis demonstrating that it would reduce the likelihood of pipeline failure.

[154] TransCanada has committed to exceeding current standards and rules for pipeline depth of burial. TransCanada stated that its own corporate standards for depth of burial is 1.0–1.2 m minimum for a pipeline right-of-way and 1.5 m minimum for a pipeline watercourse crossing. This is stricter and results in depths greater than would be calculated using a 100-year flood event. It confirmed that it would use its corporate standard depths for the project. TransCanada also committed to using horizontal directional drilling at the three main watercourse crossings with a minimum depth of burial of 48 m. It said this would help the river bed and banks remain intact.

Findings

[155] We find that the depth of burial that TransCanada has proposed exceeds the AER and CSA governing standards and sufficiently mitigates the risk of damage from hydrological events.

Project Safety Management System

[156] Fort McKay recommended a precautionary approach to design, including requiring TransCanada to adopt a process safety management system.

[157] TransCanada committed to meeting all AER and Canadian pipeline industry standards, specifications, and best practices, including those in clause 3 of *CSA Z662-15*. The requirements in *CSA Z662-15* are also AER requirements as per section 9 of the *Pipeline Rules*. Clause 3 of *CSA Z662-15* requires operating companies to develop and implement a documented safety and loss management system for pipeline systems. It states that the safety management system must provide for the protection of people, the environment, and property and cover the life cycle of the pipeline system.

Hazard Assessment and Risk Analysis

[158] One of the elements of a safety management system is conducting a hazard assessment and risk analysis. There are various methods used in such assessments. One of the commonly used methodologies is a hazard and operability study.

[159] A hazard and operability study reviews the design and identifies safety and environmental risks. The study also identifies any mitigation measures and evaluates the risk after applying the mitigation measures. The intent of the study is to ensure the identified risks are sufficiently mitigated.

[160] TransCanada conducted a hazard and operability study for the project.

[161] Fort McKay was unsatisfied with the methodology used. Fort McKay was unsatisfied with TransCanada's characterization of the risks. Fort McKay also was unsatisfied with the magnitude assigned to the risks during the hazard and operability study.

[162] CSA has general guidelines for hazard assessment and risk analysis, which the applicant must use to be compliant. Neither the *CSA Z662-15* nor the AER prescribe methodologies for hazard and risk assessments or how to apply them. How they are applied is at the discretion of the operator.

Findings

[163] We acknowledge TransCanada's commitment to comply with *CSA Z662-15* requirements. Compliance with *CSA Z662-15* requires a safety management system. We are satisfied that a safety management system that meets *CSA Z662-15* standards will be prepared and implemented by TransCanada for its project. As neither CSA nor AER prescribe specifics of a hazard and risk assessment, we find that meeting the requirements under *CSA Z662-15* for a safety management system is satisfactory.

Number and Placement of Isolation Valves

[164] Isolation valves are installed on pipelines to reduce the volume of product released in the event of a pipeline leak or rupture. *CSA Z662-15* details the requirements for valve location and spacing for pipelines. Valves must be installed on both sides of major watercourse crossings and wherever else it may be appropriate, given the terrain, to limit damage from a release. *CSA Z662-15* defines a major watercourse crossing as one that, in an event of a release, poses a significant risk to the public or environment.

[165] Operators must locate valves to minimize the damages should a leak occur. Isolation valves, operating practices, leak detection systems, and pipeline integrity management systems also play an important role in reducing the risk of a pipeline release.

[166] TransCanada proposed installing a total of five isolation valves. It committed to installing isolation valves on either side of the three main watercourses (Dover River, Mackay River, an unnamed tributary to the Mackay River; figure 1). Valves would be spaced so as to minimize the amount of oil released during a rupture. TransCanada reviewed environmental features along the route, existing land use (to reduce disturbance), local infrastructure available (access road and local power supply), local topography, and a site's geotechnical suitability when determining valve placement.

[167] TransCanada assessed the potential spill volumes from each pipeline segment between two valves. TransCanada used an outflow analysis to estimate the accidental SCO release. For this analysis, it was assumed a complete pipeline rupture would occur while SCO volumes are at peak pipeline capacity. The resulting maximum possible release volume was calculated to be 16 500 barrels. This release would be downstream of valve 4. Valve 4 would be located on the southern bank of the Mackay River. The Mackay River flows towards the Hamlet of Fort McKay and into the Athabasca River.

[168] Fort McKay recommended installing additional isolation valves to reduce potential spill volumes.

[169] No volume of oil being released into a water course is acceptable. Nevertheless, the risk of a spill exists from any pipeline. In analyzing potential release volumes for this project, for the most part, we are satisfied with the number, spacing, and locations of isolation valves proposed by TransCanada. However, we are concerned about the potential impact of a 16 500 bbl release in the immediate vicinity of the Mackay River. It should be reduced by the addition of one more isolation valve between valve IMLV 4 and valve IMLV 5. The addition of a valve, sited where it can optimize the reduction of a release occurring in this segment, satisfies our concern.

Findings

[170] We find that the isolation valve strategy with the proposed number and location of valves and the additional valve condition we are imposing is satisfactory.

Condition of Approval

[171] TransCanada must install one additional isolation valve between valve IMLV 4 and valve IMLV 5. TransCanada must conduct a study to find a location for the additional valve to reduce the magnitude of a maximum release between valve IMLV 4 to valve IMLV 5. The study must be provided to the AER and the AER must authorize the final location of the valve before operation of the pipeline.

Emergency Response

[172] Emergency response and response planning were two of the issues identified to be considered during the hearing. The requirements in the AER's *Directive 071* work to protect the public and environment from harm by ensuring that licensees of petroleum operations are ready to take the actions necessary to quickly and effectively respond to an emergency. As required by *Directive 071*, TransCanada must complete and submit an emergency response plan before it begins pipeline operations.

[173] TransCanada stated that it will follow the requirements of *Directive 071*. To help it carry out the requirements of *Directive 071*, TransCanada would have its own trained emergency response personnel, staged caches of emergency response equipment, and a number of contractors and mutual aid agreements that maintain spill contingency plans and oil spill containment and recovery units in the Fort McKay area.

Through these partnerships, TransCanada would have access to equipment located in the Fort McKay area.

[174] Fort McKay requested the following additional emergency management and preparedness activities of TransCanada:

- prepare a generic and scenario-specific (e.g., spill to lake, spill to wetland) emergency response plan;
- prepare and practice clean-up plans;
- provide, commission, and practice using clean-up equipment for water and wetland clean-up; and
- prepare notification plans and signage plans.

[175] TransCanada confirmed that these activities would take place before pipeline operations start.

[176] Fort McKay's expert witness also wanted TransCanada to obtain equipment necessary to be able to recover, within two hours, the largest expected release. Fort McKay's expert submitted that this equipment should be permanently located in either Fort McMurray or Fort McKay and that it should be deployed within an hour of a response call. The largest spill expected could be as large as 16 500 barrels.

[177] We acknowledge that no pipeline releases are acceptable and that spill recovery should occur within the shortest time feasible. We accept that Fort MacKay is concerned about the potential and significance of pipeline spills. We understand why they would seek demonstration of a timely and effective spill recovery capability. However, it is not practical to condition that the largest spill be recovered fully within two hours, nor is it likely that TransCanada would be able to have the capacity to do so. TransCanada's commitments and participation in spill response training and access to oil spill containment and recovery units in the Fort McKay area provide a reasonable level of spill response and recovery preparedness.

Findings

[178] We find that in implementing its commitments and in meeting the requirements of *Directive 071*, TransCanada will also fulfil the requirements regarding emergency response and spill contingency planning for this project.

Conclusion

[179] We considered the impact of the project on Fort McKay First Nation and the environment. We determined that the impacts of the project, after implementation of TransCanada's commitments and mitigation plans and the conditions we impose, can be mitigated to a level consistent with responsible development. Based on the submissions, evidence, and relevant legislation, we determine that the project is needed to provide for the efficient, orderly, and environmentally responsible development of Alberta's energy resources. We therefore approve with conditions the White Spruce pipeline project.

Dated in Calgary, Alberta, on February 22, 2018.

Alberta Energy Regulator

<original signed by>

R. C. McManus
Presiding Hearing Commissioner

<original signed by>

C. Chiasson
Hearing Commissioner

<original signed by>

P. Meysami
Hearing Commissioner

Appendix 1 Summary of Conditions

Conditions 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. Enforcement of an approval includes enforcement of the conditions attached to that approval. Sanctions imposed for the breach of such conditions may include the suspension of the approval, resulting in the shut-in of a facility. The conditions imposed are summarized below.

The AER expects the applicant to comply with commitments made to all parties. However, while the AER has considered these commitments in arriving at its decision, the AER cannot enforce them.

Conditions

1. Construction must be conducted only under frozen conditions.
2. If moose are identified in the immediate vicinity (right-of-way plus 100 metres) of the construction zone, TransCanada must immediately suspend work in the vicinity of the moose, assess the situation, and allow construction to resume only when the moose have moved safely away from the construction zone.
3. If a trench must be left open overnight or unattended, sloped subsoil ramps must be placed at the ends of the open trench to create egress for wildlife that might enter the trench.
4. At wildlife migration or travel corridors identified by TransCanada or the AER, TransCanada must install breaks in windrows to allow wildlife movement across the project footprint.
5. TransCanada must use a qualified archeologist to provide training in the environmental orientation program to construction personnel on recognizing potential historical resource and traditional land use sites.
6. TransCanada must prepare and submit a caribou habitat restoration plan to the AER for approval for PLA160532 and PLA160531. This plan must have the effect of restoring 2.0 times the area of new cut habitat affected in the West Side Athabasca Range by the project. The goal or outcome of the plan is to ensure that there is, at a minimum, no net loss of caribou habitat from the project in the West Side Athabasca Range. The restoration plan must be filed at least six months before operations for the White Spruce pipeline project begin and approved by the AER before operations start up. In addition to any measures that TransCanada determines should be included, the restoration plan must include
   - a list of specific restoration sites in the West Side Athabasca Range identified for restoration, including their location, area, description and site-specific restoration plans;
   - specification drawings for implementation of restoration methods at each site;

- a quantitative and qualitative assessment of the total area of caribou habitat that will be restored and how these restoration sites are equivalent to the 2.0 times the new cut area disturbed by the White Spruce pipeline project within the West Side Athabasca Range;
- a schedule indicating when restoration measures will be initiated and completed;
- a process and timeline for completing an assessment of the effectiveness and value of the restoration plan; and
- a summary of TransCanada's discussions with Fort McKay about the restoration plan, including any concerns that Fort McKay raised and how or if these concerns were addressed.

7. TransCanada must install one additional isolation valve between valve IMLV 4 and valve IMLV 5. TransCanada must conduct a study to find a location for the additional valve to reduce the magnitude of a maximum release between valve IMLV 4 to valve IMLV 5. The study must be provided to the AER and the AER must authorize the final location of the valve before operation of the pipeline.

Appendix 2 Hearing Participants

Principals and Representatives (Abbreviations used in report)
TransCanada Pipelines Limited (TransCanada) M. Ignasiak S. Damji
Fort McKay First Nation (Fort McKay) T. Razzaghi
Alberta Energy Regulator staff A. Garbe, AER Counsel R. Mueller, AER Counsel A. Blackwood L. Boswell D. Campbell L. Falstead A. Ledi G. McLean J. Parmar M. Schuster J. Smith J. Watson

Appendix 3 CNRL Press Release 1

Canadian Natural

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Horizon Oil Sands

Q3/17

Horizon Oil Sands Mining and Upgrading Activity

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Nine Months Ended	
	Sep 30 2017	Jun 30 2017	Sep 30 2016	Sep 30 2017	Sep 30 2016
Synthetic crude oil production (bbl/d) [1]	156,465	190,837	67,586	179,799	104,865

(1) During the Q3/17, no SCO production was consumed internally as diesel (Q2/17 – 438 bbl/d; Q3/16 – 1,464 bbl/d; nine months ended September 30, 2017 – 287 bbl/d; nine months ended September 30, 2016 – 2,083 bbl/d).

The Horizon Oil Sands include a surface oil sands mining and bitumen extraction plant, complemented by on-site bitumen upgrading with associated infrastructure to produce high quality synthetic crude oil ("SCO"). Canadian Natural holds extensive leases that are estimated 3.6 billion barrels of proved and probable SCO reserves. The Horizon Oil Sands are located on these leases just north of Fort McMurray, Alberta in the Athabasca region. Due to the massive resource base, the mine and plant facilities are expected to produce for decades to come without production declines normally associated with crude oil production.

Horizon - Current Phase

Construction progress to date at Horizon has met or exceeded expectations on cost and performance. Canadian Natural has a disciplined execution strategy, to achieve cost certainty for a defined and stepped expansion at our Horizon operations from Phase 1 productive capacity of 110,000 bbl/d to 250,000 bbl/d of SCO . As of Q4/14. the Horizon expansion project is 56% complete. In 2014, we advanced the completion of the project through the completion and commissioning of Phase 2A. This phase added 12,000 bbl/d of production capacity through the addition of an additional coker pair. Through this pahse and certain operational synergies, Canadian Natural was able to increase the name plate capacity to 137,000 bbl/d. In 2015, Canadian Natural will continue progress the expansion of Horizon with work on both Phases 2A and 3.

The timing of construction for future expansions is critical for cost control and we remain focused to take advantage of favorable market conditions. We are not driven to production increases at the expense of a higher capital cost. Current expansion and debottlenecking will be very deliberate and flexible to ensure projects can be started or stopped based on market conditions. The Horizon Oil Sands asset is substantial and anticipated to provide significant free cash flow well into the future. The development of this world class asset is predicated upon generating the greatest value for our shareholders.

Horizon - Planning - Past Phases

Canadian Natural's Board of Directors sanctioned the Horizon Oil Sands Project in February 2005 and after years of planning and construction, the Horizon Oil Sands successfully and sustainably produced its first barrels of high quality, low-sulphur, 34° API, sweet SCO in early 2009. First production of SCO was a major milestone for Canadian Natural and we were pleased with the success of the project. Acting as our own primary contractor on the Horizon Oil Sands, we built a core competency in executing large scale projects from the ground up and have learned a great deal from the construction and startup of Phase 1.

Phase 1 was just the first step in value creation from this significant asset. A considerable amount of capital for infrastructure was included in Phase 1 in anticipation of future phases. These include but are not limited to, support infrastructure such as the aerodrome, buildings, shops, warehouses, camps and roads, site preparation, the piperack, coker foundations, gas and power distributions, the majority of underground piping and so on. Canadian Natural is positioned to leverage the benefits from our existing operation into future expansions.

The expansions to the Horizon Oil Sands have been broken into five categories, in adopting this strategy and breaking the overall expansion into smaller, more manageable pieces Canadian Natural believes that this will lead to enhanced project and cost control. Phase 1 of the expansion was completed during 2009. This Phase included engineering and design specifications for greater production capacity, the setting of additional coker foundations, other supporting infrastructure, and the procurement of long lead equipment such as coke drums, reactors and mobile equipment. The current expansion has been re-profiled into five categories as follows:

Reliability (Tranche 2)	**- OPP 3, Hydrotransport, Sulphur Unit 3 - 5,000 bbl/d SCO capacity Increase**
Directive 74	**- Equipment and tailings process required to meet new ERCB regulations**
Phase 2A expansion	**- Upgrading debottlenecking and Coker - 12,000 bbl/d SCO capacity increase**
Phase 2B	**- OPP 4, Froth Treatment, Vacuum Distillations, Gas/Oil Hydrotreater - 45,000 bbl/d SCO capacity increase**
Phase 3	**- OPP 5, Extraction 3&4, Combined Hydrotreater, Sulphur recovery - 80,000 bbl/d SCO capacity increase**

We will see incremental production gains throughout the completion of future expansion and debottlenecking, with targeted full facility capacity of approximately 250,000 bbl/d. Further phases of expansion could potentially bring the ultimate capacity to 500,000 bbl/d.

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Appendix 4 CNRL Press Release 2

Canadian Natural

PRESS RELEASE

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
2017 SECOND QUARTER RESULTS
CALGARY, ALBERTA – AUGUST 3, 2017 – FOR IMMEDIATE RELEASE

Commenting on second quarter 2017 results, Steve Laut, President of Canadian Natural stated, "Our balanced and diverse portfolio delivered strong results in the second quarter of 2017. Funds flow from operations was significant at $1.7 billion, a strong result given the downward pressure on crude oil prices throughout the quarter. The Horizon Phase 2B expansion and acquired Athabasca oil sands volumes drove 27% growth in crude oil production volumes and 16% growth on a BOE basis, when compared with the second quarter of 2016.

In the quarter, Canadian Natural closed the transformational acquisition of the Athabasca Oil Sands Project ("AOSP"), as our teams effectively and efficiently transitioned all assets and personnel to Canadian Natural. The closing went as expected as we took over operatorship of the AOSP mines on June 1, 2017. In our first month of operating the mines results were strong, with AOSP production of approximately 202,300 bbl/d net to Canadian Natural.

Based upon strong results in the first half of the year, the Company has increased the mid-point of its 2017 annual liquids and BOE production guidance by 11,000 bbl/d and 3,000 BOE/d respectively, while decreasing its 2017 capital program by approximately $180 million."

Canadian Natural's Chief Operating Officer, Tim McKay, added, "Results from our strong balanced asset base including conventional, Horizon and AOSP helped us to achieve record monthly production of over 1,000,000 BOE/d in June 2017. At Horizon, operations continue to be strong and disciplined, with second quarter production at roughly 191,000 bbl/d of synthetic crude oil ("SCO"), above our second quarter corporate guidance of 180,000 bbl/d to 188,000 bbl/d. Operating costs were once again lower than targeted at just over $22.00/bbl of SCO, similar to the record levels achieved in the first quarter of 2017."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "The Company had another strong quarter with net earnings of approximately $1.1 billion, an increase of over $800 million from the first quarter of 2017. Year to date free cash flow was significant, allowing Canadian Natural to reduce debt in the first half of 2017 by roughly $1.2 billion, excluding acquisition related financing for AOSP and impacts of foreign exchange. We exited with strong liquidity of approximately $3.7 billion at the end of the quarter.

In the next six months Canadian Natural will reach another inflection point with full periods of production from the Horizon Phase 3 expansion and the AOSP operations, which will drive positive significant free cash flow growth and result in continued debt reduction and a balanced capital allocation."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Jun 30 2017	Mar 31 2017	Jun 30 2016	Six Months Ended Jun 30 2017	Jun 30 2016
Net earnings (loss)	**$ 1,072**	$ 245	$ (339)	**$ 1,317**	$ (444)
Per common share – basic	**$ 0.93**	$ 0.22	$ (0.31)	**$ 1.16**	$ (0.41)
– diluted	**$ 0.93**	$ 0.22	$ (0.31)	**$ 1.16**	$ (0.41)
Adjusted net earnings (loss) from operations (1)	**$ 332**	$ 277	$ (210)	**$ 609**	$ (753)
Per common share – basic	**$ 0.29**	$ 0.25	$ (0.19)	**$ 0.54**	$ (0.69)
– diluted	**$ 0.29**	$ 0.25	$ (0.19)	**$ 0.54**	$ (0.69)
Funds flow from operations (2)	**$ 1,726**	$ 1,639	$ 938	**$ 3,365**	$ 1,595
Per common share – basic	**$ 1.50**	$ 1.47	$ 0.85	**$ 2.97**	$ 1.45
– diluted	**$ 1.49**	$ 1.46	$ 0.85	**$ 2.95**	$ 1.45
Capital expenditures, excluding AOSP acquisition costs (3)	**$ 889**	$ 846	$ 1,158	**$ 1,735**	$ 2,198
Total net capital expenditures (3)	**$ 13,046**	$ 846	$ 1,158	**$ 13,892**	$ 2,198
Daily production, before royalties					
Natural gas (MMcf/d)	**1,656**	1,673	1,689	**1,664**	1,738
Crude oil and NGLs (bbl/d)	**637,127**	598,113	502,410	**617,728**	524,668
Equivalent production (BOE/d) (4)	**913,171**	876,907	783,988	**895,139**	814,259

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Funds flow from operations (formally cash flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.

(3) For additional information and details, refer to the net capital expenditures table in the Company's MD&A.

(4) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

- Canadian Natural generated funds flow from operations of $1,726 million in Q2/17, an increase of $87 million and $788 million over Q1/17 and Q2/16 levels respectively.
- The Company generated significant free cash flow in Q2/17 of approximately $840 million after net capital expenditures excluding the Athabasca Oil Sands Project ("AOSP") acquisition expenditures. After further adjusting for quarterly dividend requirements, approximately $530 million of free cash flow was realized in the quarter, which was largely used to reduce the Company's debt levels.
- For Q2/17, the Company had net earnings of $1,072 million compared to net earnings of $245 million in Q1/17 and a net loss of $339 million in Q2/16. The adjusted net earnings from operations was $332 million in Q2/17, an increase of 20% compared to adjusted net earnings of $277 million in Q1/17 and an increase of $542 million from the adjusted net loss of $210 million in Q2/16.
- Canadian Natural's corporate crude oil and NGLs production volumes averaged a record 637,127 bbl/d representing 7% and 27% increases from Q1/17 and Q2/16 levels respectively. Crude oil and NGL production volume increases were primarily due to high reliability and strong production from the Horizon Phase 2B expansion and one month of production from AOSP in the quarter.
- The Company's corporate production volumes averaged a record 913,171 BOE/d in Q2/17, representing 4% and 16% increases from Q1/17 and Q2/16 levels, despite continued reliability issues at a third party natural gas facility experienced in the quarter. The Company achieved record production of approximately 1,063,300 BOE/d in June 2017.

- A reflection of the Company's continued focus of enhancing returns on capital is evident by the 20% increase in Q2/17 adjusted net earnings over Q1/17, while production increased only 4% over the same period.
- Based upon strong results in the first half of the year, the Company has increased the mid-point of its 2017 annual liquids and BOE production guidance by 11,000 bbl/d and 3,000 BOE/d respectively, while decreasing its 2017 capital program by approximately $180 million.

▪ Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing the Company's environmental footprint. Canadian Natural is committed to reducing its GHG emissions. Since 2012 the Company has reduced its methane emissions by 35%. In addition, Canadian Natural has invested significant capital to capture and sequester CO_2. The Company has carbon capture and sequestration facilities at Horizon, a 70% working interest in the Quest Carbon Capture and Storage project at Scotford and has carbon capture facilities at its 50% interest in the NWR Refinery targeted for startup in 2018. As a result Canadian Natural will be capturing approximately 1.6 million tonnes of CO_2 a year, the equivalent of taking 330,000 motor vehicles off the road annually, making Canadian Natural one of the largest capturer and sequesterer of CO_2 of all crude oil and natural gas producers in the world.

▪ On May 31, 2017, the Company successfully closed the acquisition of a direct and indirect 70% working interest in the AOSP and 100% working interest in other heavy crude oil and thermal in situ assets. In total approximately 2,800 employees were successfully transitioned to Canadian Natural.

- In May 2017 the Company successfully executed on its funding plan for the AOSP acquisition through accessing debt capital markets and a syndicated $3.0 billion 3 year term loan facility. Approximately $5.8 billion was raised in the Canadian and US debt capital markets, with tenors ranging from 3 to 30 years, and a weighted average interest rate of approximately 3.56%, with a weighted average tenor of approximately 12 years.
- During Canadian Natural's first month of AOSP ownership, operations were transitioned safely and high reliability was achieved, resulting in strong production that reached approximately 289,000 bbl/d (202,300 bbl/d net) of AOSP synthetic crude oil ("SCO") in June 2017. A combination of higher production and modest integration savings resulted in operating costs of $27.50/bbl of upgraded products.

▪ At Horizon, Q2/17 production was 190,837 bbl/d of SCO, over 6,000 bbl/d of SCO above the midpoint of the Company's previously issued quarterly guidance, representing an increase of 60% over Q2/16 levels.

- Through safe, steady and reliable operations and a strong focus on continuous improvement, the Company realized quarterly average operating costs at Horizon of $22.09/bbl of SCO in Q2/17, consistent with record low operating costs of $22.08/bbl of SCO in Q1/17 and an 18% reduction from Q2/16 levels.
- During Q2/17, Canadian Natural continued to advance the Horizon Phase 3 expansion. The expansion is currently ahead of schedule and costs are trending at the Company's 2017 estimates. Phase 3 reached 96% physical completion as at June 30, 2017 and will be mechanically complete and ready for tie-in and commissioning with the planned September turnaround.
- The Company has deferred approximately $315 million of Horizon project capital into 2018 to better plan and execute the Company's mature fines tailings project, at which time it is expected that learnings and synergies can be leveraged between the Horizon and AOSP mines to capture potential cost savings.
- The Company previously announced a potential debottleneck at the fractionation tower after startup of Horizon Phase 2B. The fractionation tower was identified as a limiting component in exceeding the targeted capacity of 250,000 bbl/d of SCO. It has now been determined that the capacity of the vacuum distillate unit ("VDU") and diluent recovery unit ("DRU") furnaces will also be limiting components in exceeding the targeted capacity.
    - A significant amount of process engineering to determine the capacity outcomes of all the critical components of the upgrading operation was completed at various confidence levels. As a result it is not prudent at present to predict with confidence, that Horizon will be able to deliver production levels exceeding 250,000 bbl/d of SCO until the Company has actual throughput through the upgrader and the actual reliability is determined once Phase 3 is operational.
    - The Company is confident that increased reliability and creep capacity volumes will be attainable if work is undertaken on the fractionator and furnaces and therefore will be undertaking this planned work during the September turnaround, extending the turnaround from 24 days to 45 days.
    - The total additional work is targeted to require capital of approximately $170 million for Optimization and Reliability enhancements.

        - The Company's annual 2017 production guidance at Horizon remains unchanged at 170,000 - 184,000 bbl/d, despite the increase in planned downtime by 21 days. This is due to the strong production results in the first half of 2017.
    - Q2/17 Horizon project capital expenditures were $182 million. The Company has reduced the Horizon 2017 project capital by $315 million and incorporated $170 million for Optimization and Reliability enhancements to take place during the Q3/17 turnaround. Total annual 2017 Horizon project capital is now targeted to be $910 million and is forecasted to be approximately $145 million lower than the previously issued 2017 capital guidance. Start-up of Phase 3 is targeted for Q4/17 and is targeted to bring total Horizon production volumes to 250,000 bbl/d of SCO, which will result in a further step change towards sustainable funds flow and lower operating costs.
- Thermal in situ operations were strong in Q2/17 with production averaging 105,719 bbl/d, representing a 13% increase from Q2/16 levels and above the Company's previously issued quarterly guidance. Results were strong given planned turnaround activities in the quarter at both Primrose and Kirby South.
    - Kirby South, the Company's Steam Assisted Gravity Drainage ("SAGD") project achieved production of 34,649 bbl/d in Q2/17, despite planned downtime for turnaround activities.
        - Including energy costs, operating costs of $10.28/bbl were achieved in the quarter at Kirby South, in-line with Q2/16 levels and were supported by a strong Steam to Oil Ratio ("SOR") of 2.6.
    - Primrose production was 71,070 bbl/d in Q2/17, despite planned downtime for turnaround activities.
        - The Company's low pressure steamflood at Primrose East continues to be strong, with June 2017 production under steamflood averaging approximately 32,000 bbl/d.
- Pelican Lake heavy crude oil production of 46,932 bbl/d in Q2/17 was in line with Q1/17 and Q2/16 levels. Operations continued to be optimized in the quarter, resulting in industry leading operating costs of $6.38/bbl in Q2/17, flat from Q1/17 and a 6% decrease from Q2/16 levels.
- Primary heavy crude oil production averaged 89,345 bbl/d in Q2/17. The Company's proactive decision to reduce its primary heavy crude oil drilling program in 2015 and the first half of 2016 resulted in production volumes of primary heavy crude oil declining 14% from Q2/16 levels.
- North America light crude oil and NGL quarterly production averaged 90,806 bbl/d, 1% and 8% increases from Q1/17 and Q2/16 levels respectively. Quarterly operating costs of $13.98/bbl were realized in Q2/17, in line with Q1/17 levels.
- Within the Company's North America natural gas assets, operations continued to be optimized during the quarter with Q2/17 production of 1,603 MMcf/d. Operating costs of $1.17/Mcf were achieved in the quarter, a decrease of 3% from Q1/17 levels. Production was lower than expected in the quarter due to continued reliability issues at a third party natural gas facility. During the quarter, the Company averaged production of approximately 52 MMcf/d from this facility, 36 MMcf/d less than the estimate that was incorporated in the Company's Q2/17 production guidance, and well below both the Q1/17 volumes of approximately 100 MMcf/d and Canadian Natural's productive capability for the plant, which currently exceeds 170 MMcf/d.
- International quarterly crude oil production volumes were within the Company's production guidance and averaged 46,784 bbl/d in Q2/17, an increase of 2% from Q1/17 levels.
- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. In Q2/17 the Company increased its previously existing bank credit facilities by $0.7 billion and at June 30, 2017 had in place $3.7 billion of liquidity.
    - Canadian Natural continues to have significant support from its large and diverse banking group as indicated by extensions and credit facility increases during the quarter. In Q2/17, the Company's $1.5 billion non-revolving facility was increased to $2.2 billion and extended from April 2018 to October 2019. Additionally, the Company extended $2.095 billion of the $2.425 billion revolving syndicated credit facility originally maturing in June 2019 to June 2021. The remaining $330 million will mature in June 2019.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.275 per share payable on October 1, 2017.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK sector of the North Sea and Offshore Africa. Canadian Natural's production is well balanced between light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen and SCO (herein collectively referred to as "crude oil"), natural gas and NGLs. This balance provides optionality for capital investments, facilitating improved value for the Company's shareholders.

Underpinning this asset base is long-life, low decline production from Horizon Oil Sands and the AOSP mining and upgrading, thermal in situ oil sands and Pelican Lake heavy crude oil assets. The combination of low decline, low reserve replacement costs, and effective and efficient operations means these assets provide substantial and sustainable cash flow throughout the commodity price cycle.

Augmenting this, Canadian Natural maintains a substantial inventory of low capital exposure projects within its conventional asset base. These projects can be executed quickly, and, with the right economic conditions, can provide excellent returns and maximize value for shareholders. Supporting these projects is the Company's undeveloped land base which enables large, repeatable drilling programs; programs that can be optimized over time. Additionally, by owning and operating most of the related infrastructure, Canadian Natural is able to control a major component of its operating cost and minimize production commitments. Low capital exposure projects can typically be easily stopped or started depending upon success, market conditions, or corporate needs.

Canadian Natural's balanced portfolio, built with both long-life, low decline assets and low capital exposure assets, enables effective capital allocation, production growth and value creation.

Drilling Activity

	Six Months Ended June 30			
	2017		2016	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**236**	**216**	11	8
Natural gas	**16**	**16**	6	5
Dry	**3**	**3**	—	—
Subtotal	**255**	**235**	17	13
Stratigraphic test / service wells	**232**	**232**	200	200
Total	**487**	**467**	217	213
Success rate (excluding stratigraphic test / service wells)		**99%**		100%

- The Company's total Q2/17 crude oil and natural gas drilling program of 68 net wells, excluding strat/service wells, was a significant increase from the 1 net well drilled in Q2/16. The change in drilling reflects the flexibility of Canadian Natural's resource development program and the Company's disciplined capital allocation process.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil and NGLs production (bbl/d)	**227,083**	231,591	235,468	**229,325**	243,705
Net wells targeting crude oil	**57**	147	—	**204**	7
Net successful wells drilled	**55**	147	—	**202**	7
Success rate	**96%**	100%	—	**99%**	100%

- Quarterly production volumes of North America crude oil and NGLs averaged 227,083 bbl/d in Q2/17, within quarterly corporate guidance and comparable to Q1/17 levels. Q2/17 production volumes represent a decrease of 4% from Q2/16 levels as a result of limited drilling activity in 2016.

- Pelican Lake heavy crude oil production of 46,932 bbl/d in Q2/17 was in line with Q1/17 and Q2/16 levels. Operations continued to be optimized in the quarter, resulting in industry leading operating costs of $6.38/bbl in Q2/17 flat from Q1/17 levels and a 6% decrease from Q2/16 levels.
- Primary heavy crude oil production averaged 89,345 bbl/d in Q2/17. The Company's proactive decision to reduce its primary heavy crude oil drilling program in 2015 and the first half of 2016 resulted in production volumes declining 14% from Q2/16 levels.
- North America light crude oil and NGL quarterly production averaged 90,806 bbl/d, 1% and 8% increases from Q1/17 and Q2/16 levels respectively. Strong quarterly operating costs of $13.98/bbl were realized in Q2/17, in line with Q1/17 levels.
- The Company's 2017 North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range from 236,000 bbl/d - 246,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Bitumen production (bbl/d)	**105,719**	128,372	93,213	**116,983**	105,629
Net wells targeting bitumen	**4**	8	—	**12**	—
Net successful wells drilled	**4**	8	—	**12**	—
Success rate	**100%**	100%	—	**100%**	—

- Thermal in situ operations were strong in Q2/17 with production averaging 105,719 bbl/d, representing a 13% increase from Q2/16 levels and above the Company's previously issued quarterly guidance. Results were strong given planned turnaround activities in the quarter at both Primrose and Kirby South.
    - Kirby South, the Company's SAGD project achieved production of 34,649 bbl/d in Q2/17, despite planned downtime for turnaround activities. Including energy costs, operating costs of $10.28/bbl were achieved in the quarter, in-line with Q2/16 levels, supported by a strong Steam to Oil Ratio ("SOR") of 2.6.
    - Primrose production was 71,070 bbl/d in Q2/17, after planned downtime for turnaround activities. Including energy costs, operating costs of $15.87/bbl were realized in Q2/17**,** a strong result given the planned downtime for turnaround activities and steam generation work in the quarter.
        - Strong results from the Company's low pressure steamflood at Primrose continue to be achieved, with June 2017 production under steamflood averaging approximately 32,000 bbl/d.
- Kirby North, the Company's second SAGD project targeted to add 40,000 bbl/d, continues to be on track as civil and cement foundation work has commenced at the plant site. As previously announced, the remaining project capital is targeted to be approximately $650 million, with steam-in targeted for late 2019 and first production targeted in early 2020.
- The Company's 2017 thermal in situ annual production guidance has been increased and is targeted to range from 112,000 bbl/d - 122,000 bbl/d.

Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Natural gas production (MMcf/d)	**1,603**	1,613	1,620	**1,607**	1,672
Net wells targeting natural gas	**5**	12	1	**17**	5
Net successful wells drilled	**5**	11	1	**16**	5
Success rate	**100%**	92%	100%	**94%**	100%

- North America natural gas production volumes averaged 1,603 MMcf/d in Q2/17, in line with Q1/17 and Q2/16. Production was lower than expected due to the continued reliability issues at a third party natural gas facility. The third party facility was down from June 6, 2017 to July 28, 2017 and is now running at partial capacity. However it is not expected to have reliable production until after a planned turnaround in September. This further impacts Q3/17 and annual 2017 volumes, resulting in the Company lowering its annual production guidance. Canadian Natural's current production capability through this facility is in excess of 170 MMcf/d.

- The Company's North America natural gas operations achieved operating costs of $1.17/Mcf in Q2/17, a decrease of 3% from Q1/17.
- The Company’s 2017 total natural gas annual production guidance has been changed and is now targeted to range from 1,655 MMcf/d - 1,705 MMcf/d to reflect the poor reliability of a third party natural gas facility for the first half of the year and additional unplanned and planned downtime in the second half of the year.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil production (bbl/d)					
North Sea	**26,304**	23,042	23,360	**24,682**	23,338
Offshore Africa	**20,480**	22,616	30,858	**21,542**	28,286
Natural gas production (MMcf/d)					
North Sea	**37**	37	30	**37**	29
Offshore Africa	**16**	23	39	**20**	37
Net wells targeting crude oil	**1.8**	—	—	**1.8**	1.2
Net successful wells drilled	**1.8**	—	—	**1.8**	1.2
Success rate	**100%**	—	—	**100%**	100%

- International quarterly crude oil production volumes were within the Company's production guidance and averaged 46,784 bbl/d in Q2/17, an increase of 2% from Q1/17.
  - In the North Sea, the Company's continued focus on production enhancements, increased reliability and water flood optimization, and a modest drilling program of 1.8 net wells resulted in average production volumes of 26,304 bbl/d in Q2/17, an increase of 14% and 13% from Q1/17 and Q2/16 levels respectively.
  - North Sea quarterly crude oil operating costs decreased to $28.86/bbl, representing reductions of 22% and 39% from Q1/17 and Q2/16 levels respectively.
    - The Company successfully decommissioned the Murchison platform in Q2/17, on time and on budget.
    - The Company commenced its first step in the decommissioning and abandonment of the Ninian North platform with cessation of production on May 18, 2017. Well abandonment activities are currently underway.
  - Offshore Africa production volumes averaged 20,480 bbl/d in Q2/17, a 9% decrease from Q1/17 levels. Production expense of $17.27/bbl was achieved, related to the Baobab and Espoir fields in Cote d'Ivoire in Q2/17. After incorporating production from the Olowi field in Gabon, production expense was $32.39/bbl.
    - Canadian Natural completed a planned turnaround in Q2/17 at Espoir.
    - The Company also completed a planned turnaround at Baobab in Q3/17, which is reflected in Q3/17 production guidance.
- The Company's 2017 International annual production guidance remains unchanged and is targeted to range from 43,000 bbl/d - 49,000 bbl/d.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Synthetic crude oil production (bbl/d) (1)	**190,837**	192,491	119,511	**191,660**	123,710

(1) Second quarter 2017 SCO production before royalties excludes 438 bbl/d of SCO consumed internally as diesel (first quarter 2017 – 428 bbl/d; second quarter 2016 – 2,227 bbl/d; six months ended June 30, 2017 - 433 bbl/d; six months ended June 30, 2016 - 2,394 bbl/d).

- At Horizon, Q2/17 production was 190,837 bbl/d of SCO, over 6,000 bbl/d of SCO above the midpoint of the Company's previously issued quarterly guidance, representing an increase of 60% over Q2/16 levels.
  - Through safe, steady and reliable operations and a strong focus on continuous improvement, the Company realized quarterly average operating costs at Horizon of $22.09/bbl of SCO in Q2/17, consistent with record low operating costs of $22.08/bbl of SCO in Q1/17 and an 18% reduction from Q2/16 levels.
  - During Q2/17, Canadian Natural continued to advance the Horizon Phase 3 expansion. The expansion is currently ahead of schedule and costs are trending at the Company's 2017 estimates. Phase 3 reached 96% physical completion as at June 30, 2017 and will be mechanically complete and ready for tie-in and commissioning with the planned September turnaround.
  - The Company has deferred approximately $315 million of Horizon project capital into 2018 to better plan and execute the Company's mature fines tailings project, at which time it is expected that learnings and synergies can be leveraged between the Horizon and AOSP mines to capture potential cost savings.
  - The Company previously announced a potential debottleneck at the fractionation tower after startup of Horizon Phase 2B. The fractionation tower was identified as a limiting component in exceeding the targeted capacity of 250,000 bbl/d of SCO. It has now been determined that the capacity of the VDU and DRU furnaces will also be limiting components in exceeding the targeted capacity.
    - A significant amount of process engineering to determine the capacity outcomes of all the critical components of the upgrading operation was completed at various confidence levels. As a result it is not prudent at present to predict with confidence, that Horizon will be able to deliver production levels exceeding 250,000 bbl/d of SCO until the Company has actual throughput through the upgrader and the actual reliability is determined once Phase 3 is operational.
    - The Company is confident that increased reliability and creep capacity volumes will be attainable if work is undertaken on the fractionator and furnaces and therefore will be undertaking this planned work during the September turnaround, extending the turnaround from 24 days to 45 days.
    - The total additional work is targeted to require capital of approximately $170 million for Optimization and Reliability enhancements.
  - Q2/17 Horizon project capital expenditures were $182 million. The Company has reduced the Horizon 2017 project capital by $315 million and incorporated $170 million for Optimization and Reliability enhancements to take place during the Q3/17 turnaround. Total annual 2017 Horizon project capital is now targeted to be $910 million and is forecasted to be approximately $145 million lower than the previously issued 2017 capital guidance. Start-up of Phase 3 is targeted for Q4/17 and is targeted to bring total Horizon production volumes to 250,000 bbl/d of SCO, which will result in a further step change towards sustainable funds flow and lower operating costs.
- Directive 85 (formerly Directive 74) implementation at the Horizon project remains on track and was 71% physically complete as at June 30, 2017. This project includes research into tailings management and investments in technological advancements to advance the cessation of the use of traditional tailings ponds.
- The Company's 2017 Horizon annual production guidance remains unchanged and is targeted to range from 170,000 bbl/d - 184,000 bbl/d of SCO.

North America Oil Sands Mining and Upgrading – AOSP

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Synthetic crude oil production (bbl/d) (1)	**66,704**	—	—	**33,536**	—

(1) Consists of heavy and light synthetic crude oil products.

- At AOSP, Canadian Natural's 70% working interest in this world class oil sands mining and upgrading operation, strong monthly net production of 202,300 bbl/d of AOSP SCO was achieved in June 2017. As such, Q2/17 production was 66,704 bbl/d of upgraded product, above the top end of the Company's previously issued guidance of 57,000 - 63,000 bbl/d.
  - On May 31, 2017, the Company successfully closed the acquisition of a direct and indirect 70% working interest in the AOSP and 100% working interest in other heavy crude oil and thermal in situ assets. In total approximately 2,800 employees were successfully transitioned to Canadian Natural.
- A combination of higher production and modest integration savings resulted in low operating costs in the quarter of $27.50/bbl of upgraded product.
- The Company's 2017 AOSP annual production guidance has been increased and is now targeted to range from 102,000 bbl/d - 116,000 bbl/d of AOSP SCO.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil and NGL pricing					
WTI benchmark price (US$/bbl) (1)	**$ 48.29**	$ 51.86	$45.60	$ 50.07	$ 39.56
WCS blend differential from WTI (%) (2)	**23%**	28%	29%	26%	35%
SCO price (US$/bbl)	**$ 49.83**	$ 51.45	$ 47.39	$ 50.63	$ 40.58
Condensate benchmark pricing (US$/bbl)	**$ 48.44**	$ 52.21	$ 44.10	$ 50.31	$ 39.28
Average realized pricing before risk management (C$/bbl) (3)	**$ 47.12**	$ 47.05	$ 39.98	$ 47.08	$ 31.40
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.63**	$ 2.79	$ 1.18	$ 2.71	$ 1.59
Average realized pricing before risk management (C$/Mcf)	**$ 2.97**	$ 3.25	$ 1.50	$ 3.11	$ 1.88

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

- WTI averaged US$48.29/bbl in Q2/17, an increase of 6% from US$45.60/bbl in Q2/16, and a decrease of 7% from $51.86/bbl in Q1/17.
- Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US $50.24/bbl in Q2/17, an increase of 10% from US$45.80/bbl in Q2/16, and a decrease of 7% from $54.05/bbl in Q1/17.
- WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. Benchmark pricing continued to reflect the OPEC decision in November 2016 to implement a production cut effective January 1, 2017 followed by additional production cuts by certain non-OPEC countries. The decrease in benchmark pricing in Q2/17 from Q1/17 reflects increased production in certain non-OPEC countries.
- The WCS Heavy Differential averaged US$11.11/bbl in Q2/17, a decrease of 17% from US$13.31/bbl in Q2/16, and a decrease of 24% from $14.58/bbl in Q1/17. The WCS Heavy Differential largely reflects US Gulf Coast pricing,

adjusted for transportation costs. The narrowing of the differential in Q2/17 compared with Q1/17 primarily reflects seasonality.

- Canadian Natural contributed approximately 203,000 bbl/d of its heavy crude oil stream to the WCS blend in Q2/17. The Company remains the largest contributor to the WCS blend, accounting for 44% of the total blend.
- The SCO price averaged US$49.83/bbl in Q2/17, an increase of 5% from $47.39/bbl in Q2/16, and a decrease of 3% from US$51.45/bbl in Q1/17. The fluctuations in SCO pricing from the comparable periods were primarily due to changes in WTI benchmark pricing and the impact of unplanned third party oil sands production outages.
- AECO natural gas prices averaged $2.63/GJ in Q2/17, an increase of 123% from $1.18/GJ in Q2/16, and a decrease of 6% from $2.79/GJ in Q1/17. The increase in natural gas prices in Q2/17 compared with Q2/16 primarily reflected the rebalancing of natural gas storage inventory to historically normal levels, primarily due to reduced drilling activity in 2016, resulting in lower US natural gas production. Additionally, pricing reflected colder weather in the 2016/2017 winter season as compared with the previous year. The decrease in natural gas prices compared with the Q1/17 primarily reflected seasonal demand factors.
- The North West Redwater refinery, upon completion, will strengthen the Company's position by providing a competitive return on investment and by adding 50,000 bbl/d of bitumen conversion capacity in Alberta which will help reduce pricing volatility in all Western Canadian heavy crude oil. The Company has a 50% interest in the North West Redwater Partnership. For project updates, please refer to: https://nwrsturgeonrefinery.com/whats-happening/news/.

FINANCIAL REVIEW

The Company continues to implement proven strategies and its disciplined approach to capital allocation. As a result, the financial position of Canadian Natural remains strong. Canadian Natural's cash flow generation, credit facilities, US commercial paper program, diverse asset base and related flexible capital expenditure programs all support a flexible financial position and provide the appropriate financial resources for the near-, mid- and long-term.

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved record production levels of 913,171 BOE/d in Q2/17, with approximately 97% of total production located in G7 countries. During the month of June 2017, total company production averaged approximately 1,063,300 BOE/d.
- The Company generated significant free cash flow in Q2/17 of approximately $840 million after net capital expenditures and excluding AOSP acquisition expenditures. After further adjusting for quarterly dividend requirements, approximately $530 million of free cash flow was realized in the quarter, which was largely used to reduce the Company's debt levels.
- In May 2017 the Company successfully executed on its funding plan for the acquisition through accessing debt capital markets and a syndicated $3.0 billion 3 year term loan facility. Approximately $5.8 billion was raised in the Canadian and US debt capital markets with tenors ranging from 3 to 30 years and a weighted average interest rate of approximately 3.56% with a weighted average tenor of approximately 12 years.
- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. In Q2/17 the Company increased its previously existing bank credit facilities by $0.7 billion and at June 30, 2017 had in place $3.7 billion of liquidity.
    - Canadian Natural continues to have significant support from its large and diverse banking group as indicated by extensions and credit facility increases during the quarter. The company's $1.5 billion non-revolving facility was increased to $2.2 billion and extended from April 2018 to October 2019. Additionally, the Company extended $2.095 billion of the $2.425 billion revolving syndicated credit facility originally maturing in June 2019 to June 2021. The remaining $330 million will mature in June 2019.
- During Q2/17, the Company repaid US$1.1 billion of 5.70% notes which was fully hedged using a cross currency swap, resulting in a payment on settlement of $1.287 billion.
- Balance sheet strength continues to be a focus of the Company, with debt to book capitalization of 43% at June 30, 2017, within the Company's targeted operating range.
- In addition to its strong cash flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at June 30, 2017, these financial levers include the Company's third party investments of approximately $832 million.

- At June 30, 2017, 50,000 GJ/d of natural gas volumes were hedged using AECO swaps through to October 2017. Additionally, 67,000 bbl/d of crude oil volumes were hedged through to December 2017 using WTI costless collars with a floor of US$50.00. For full hedging disclosure please see the Company's website.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.275 per share payable on October 1, 2017.

OUTLOOK

The Company forecasts annual 2017 production levels to average between 663,000 and 717,000 bbl/d of crude oil and NGLs and between 1,655 and 1,705 MMcf/d of natural gas, before royalties. Q3/17 production guidance before royalties is forecast to average between 740,000 and 778,000 bbl/d of crude oil and NGLs and between 1,650 and 1,710 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company’s website at www.cnrl.com.

Canadian Natural's annual 2017 capital expenditures are targeted to be approximately $3.9 billion.

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout the Company's Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and natural gas liquids ("NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets, including the interests in AOSP as well as additional working interests in certain other producing and non-producing oil and gas properties (the "other assets"), acquired by the Company on May 31, 2017; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company’s operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management’s estimates or opinions change.

Special Note Regarding Currency, Production and Non-GAPP Financial Measures

This release should be read in conjunction with the Management's Discussion and Analysis ("MD&A") and the unaudited interim Consolidated Financial Statements for the three months and six months ended June 30, 2017 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2016.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the period ended June 30, 2017 and MD&A have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board. This release includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings (loss) from operations, funds flow from operations (previously referred to as cash flow from operations), and adjusted cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the “Financial Highlights” section of the Company's MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of the Company's MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of the Company's MD&A.

A Barrel of Oil Equivalent (“BOE”) is derived by converting six thousand cubic feet (“Mcf”) of natural gas to one barrel (“bbl”) of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of the Company's MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO.

Production volumes and per unit statistics are presented throughout this release on a “before royalty” or “gross” basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an “after royalty” or “net” basis is also presented for information purposes only in the Company's MD&A.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, August 3, 2017.

The North American conference call number is 1-866-521-4909 and the outside North American conference call number is 001-647-427-2311. Please call in 10 minutes prior to the call starting time.

An archive of the broadcast will be available until 6:00 p.m. Mountain Time, Thursday, August 17, 2017. To access the rebroadcast in North America, dial 1-800-585-8367. Those outside of North America, dial 001-416-621-4642. The conference archive ID number is 21866168.

The conference call will also be Webcast live on the internet and may be accessed on the home page our website at www.cnrl.com.

For further information, please contact:

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Toronto Stock Exchange
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Appendix 5 Pembina News Release

Pembina Completes Horizon Pipeline On Schedule

Thu, 03 Jul 2008

CALGARY, July 3 /CNW/ - Pembina Pipeline Income Fund (TSX: PIF.UN) is pleased to report the successful completion of the Horizon Pipeline by its wholly owned subsidiary Pembina Pipeline Corporation ("Pembina"). Work on the $400 million project, which began in November 2006, was substantially completed on July 1, 2008, on schedule.

Pembina acquired the Alberta Oilsands Pipe Line ("AOSPL"), now referred to as the Syncrude Pipeline, in late 2001 and since that time has spent over $600 million to expand its service offering in the Athabasca oil sands region. In 2004, Pembina completed a capacity expansion of the Syncrude Pipeline, which provides 389,000 barrels per day ("bpd") of dedicated synthetic crude oil transportation capacity to Syncrude Canada Ltd. The following year, Pembina completed construction of the 136,000 bpd Cheecham Lateral pipeline. The Horizon Pipeline, which will provide 250,000 bpd of dedicated transportation capacity to Canadian Natural Resources Limited's ("CNRL") Horizon Oil Sands Project, entailed completion of the twinning of the original AOSPL asset and construction of 73 kilometres of new pipeline connecting to CNRL's oil sands facility. Pembina now has 775,000 bpd of fully contracted synthetic crude oil transportation capacity in three distinct pipelines serving customers in this region.

Glen Fyfe, Pembina's Project Manager for these undertakings, commented: "The Horizon Pipeline is the largest pipeline project ever undertaken by Pembina and we are proud to have completed it on schedule. Since expansion of AOSPL began in 2002, Pembina has achieved a total of over 2.5 million man hours of work without a lost time safety incident. Pembina would like to thank, and to congratulate, all of the designers, suppliers, contractors and other stakeholder groups involved with the successful execution of these projects during a period of unprecedented construction challenges in the Fort McMurray to Edmonton corridor."

The Horizon Pipeline will be operated under the terms of a 25-year extendible transportation agreement providing Pembina a fixed return on invested capital and full recovery of operating costs. Pembina projects that the Horizon Pipeline will contribute incremental net operating income of $45 million per year over the 25-year contract term, commencing on August 1, 2008.

Pembina will continue to focus on the expansion of its service capability in the growing oil sands and heavy oil sector. Pembina's Mick Dilger, Vice President Business Development, stated: "The Horizon Project is representative of the ongoing optimization and build-out of our existing asset portfolio. This model enables Pembina to offer competitive service to customers while realizing attractive returns and minimizing our operating footprint and environmental impact. We expect to employ a similar strategy in the construction of our proposed Nipisi and Mitsue Pipelines. Further, Pembina's existing investments in oil sands and heavy oil infrastructure have embedded growth opportunities which we hope to realize as our customers undertake planned expansion of their oil sands production facilities in the future."

Pembina Pipeline Income Fund (TSX: PIF.UN, PIF.DB.B) is among the leading issuers in the Canadian energy infrastructure trust sector. Pembina's extensive network of conventional liquids feeder pipelines, and growing presence in the oil sands, heavy oil and midstream sectors, provide an integral service to the western Canadian energy industry. This balanced portfolio of premium, long-life energy infrastructure assets supports the stability and sustainability of the Fund. Information on the Pembina Pipeline Income Fund (the "Fund") is available on the Company's website at www.pembina.com (http://www.pembina.com).

Forward-Looking Information and Statements

This document contains certain forward-looking statements that are based on the Fund's current expectations, estimates, projections and assumptions in light of its experience and its perception of historical trends. In particular, this document contains forward-looking statements regarding net operating income, which is based upon the assumptions that the pipeline system will be in service on August 1, 2008, that future tolls are consistent with internal projections, that counterparties fulfill their contract obligations in a timely manner, that there are no unforeseen events preventing performance of contracts by Pembina, and that there are no unforeseen material costs relating to the pipeline system which are not recoverable from shippers. In some cases, forward-looking statements and information can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates", "targets", "believes", "strives", "estimates", "continue", "designed", "objective", "maintain", "schedule", "endeavor" and similar expressions. The forward-looking statements are not guarantees of future performance and are subject to a number of known and unknown risks and uncertainties, including, but not limited to: the impact of competitive entities and pricing; reliance on key industry partners, alliances and agreements; the strength and operations of the oil and natural gas production industry and related commodity prices; the continuation or completion of third party projects; regulatory environment and inability to obtain required regulatory approvals; tax laws and treatment; fluctuations in operating results; the ability of Pembina to raise sufficient capital to complete future projects and satisfy future commitments; construction delays; labour and material shortages; and certain other risks detailed from time to time in the Fund's public disclosure documents. The Fund believes the expectations and material factors and assumptions reflected in these forward-looking statements are reasonable as of the date hereof, but no assurance can be given that these expectations, factors and assumptions will prove to be correct. Undue reliance should not be placed on these forward-looking statements as both known and unknown risks and uncertainties, including those business risks stated above, may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted, forecasted or projected. Such forward-looking statements are expressly qualified by the above statements. The Fund does not undertake any obligation to publicly update or revise any forward-looking statements or information contained herein, except as required by applicable laws. Management of the Fund approved the financial outlook contained herein as of the date of this press release. The purpose of the financial outlook contained herein is to give the reader an indication of the value to Pembina of the Horizon Pipeline. Readers should be aware that the information contained in the financial outlook contained herein may not be appropriate for other purposes.

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