ISSUE: APRIL 2020 DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

This monthly report summarizes matters under the jurisdiction of the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission ("AUC") and the Canada Energy Regulator ("CER") and proceedings resulting from these energy regulatory tribunals. For further information, please contact a member of the RLC Team*.*

Regulatory Law Chambers ("RLC") is a Calgary based boutique law firm, specializing in energy and utility regulated matters. RLC works at understanding clients' business objectives and develops legal and business strategies with clients. RLC follows a team approach, including when working with our clients and industry experts. Visit our website to learn more about RLC*.*

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ALBERTA COURT OF APPEAL

Fort McKay First Nation v. Prosper Petroleum Ltd., 2020 ABCA 163

Bitumen Recovery Project - Crown Consultation - Honour of the Crown

In this decision, the Alberta Court of Appeal ("ABCA") considered an appeal from the Fort McKay First Nation ("FMFN") of the AER's approval of an application by Prosper Petroleum Ltd. ("Prosper") for the Rigel bitumen recovery project (the "Project" or "Rigel Project"). The ABCA allowed the appeal.

Background

The FMFN is an "aboriginal people of Canada" under section 35 of the *Constitution Act*, 1982 and a "band" within the meaning of the *Indian Act*, RSC 1985, c I-5 that has Treaty 8 rights to hunt, fish and trap within the Moose Lake Area, part of its traditional territory. Due to the extensive industrial and resource development surrounding Fort McKay, FMFN has been concerned regarding the cumulative effect of oil sands on its members' ability to pursue their traditional way of life in the Moose Lake Area.

The MLAMP Negotiations

The FMFN began negotiating with Alberta in 2001 to obtain protection for the Moose Lake Area. They began discussing a possible Moose Lake Access Management Plan ("MLAMP") in 2003 to address the cumulative effects of oil sands development on the FMFN's Treaty 8 rights. The MLAMP negotiations were delayed while the Lower Athabasca Regional Plan (the "LARP") was negotiated and implemented.

The LARP is a regional plan under the *Alberta Land Stewardship Act* to manage the region's natural resources. It was envisaged that, once finalized, the MLAMP would be adopted as a sub-plan of the LARP.

In March 2015, Premier Prentice and Chief Boucher signed a Letter of Intent to confirm "our mutual commitment and interest in an expedited completion of the [MLAMP]." Despite the 2015 Letter of Intent, characterized by FMFN as the "Prentice Promise," the MLAMP has still not been finalized and is the subject of ongoing negotiations between Alberta and the FMFN.

Prosper's Application to the AER

Prosper was the proponent of the Rigel Project, a proposed bitumen recovery project that would use steam-assisted gravity drainage to produce 10,000 barrels a day. On June 12, 2018, the AER found the Project to be in the public interest and approved the Project subject to authorization by Cabinet pursuant to s 10(3)(a) of *Oil Sands Conservation Act*, RSA 2000, c O-7 ("*OSCA*").

Discussion

The Jurisdiction of the AER

The ABCA noted that tribunals have the explicit powers conferred upon them by their constituent statutes. However, where empowered to consider questions of law, tribunals also have the implied jurisdiction to consider issues of constitutional law as they arise, absent a clear demonstration the legislature intended to exclude such jurisdiction. This is all the more so where the tribunal is required to consider the "public interest". In such circumstances, the regulatory agency has a duty to apply the Constitution and ensure its decision complies with section 35 of the *Constitution Act*, 1982. The tribunal cannot ignore that aspect of its public interest mandate.

The ABCA, therefore, found that the AER has the implied jurisdiction to consider issues of constitutional law as they arise in its proceedings. Under section 21 of the *Responsible Energy Development Act,* SA 2012, c R-17.3 ("*REDA*"), that jurisdiction is explicitly removed where the adequacy of Crown consultation is concerned. However, the ABCA found that issues of constitutional law outside the parameters of consultation remain within the AER's jurisdiction, including as they relate to the honour of the Crown.

The ABCA noted that, in determining whether the Project was in the "public interest", the AER considered the effect on FMFN's treaty rights generally but declined to consider whether approval would frustrate MLAMP negotiations. It gave three reasons for that narrow approach:

(a) section 21 of *REDA* prohibits the AER from assessing the adequacy of Crown consultation;

(b) section 7(3) of LARP prohibits the AER from "adjourning, deferring, denying, refusing, or rejecting any application" by reason only of incompletion of a LARP regional plan; and

(c) AER approval of the Project under s 10(3) of *OSCA* is subject to authorization by Cabinet, which is "the most appropriate place for a decision on the need to finalize MLAMP".

Section 21 of REDA

The ABCA emphasized that, when an energy project is under consideration in Alberta that could affect the treaty interests of a First Nation, the provincial Crown has a duty to consult and potentially accommodate. This duty stems from the honour of the Crown, a constitutional principle. However, section 21 of *REDA* provides:

> The [AER] has no jurisdiction with respect to assessing adequacy of Crown consultation associated with the rights of aboriginal peoples as recognized and affirmed under Part II of the *Constitution* Act, 1982.

The ABCA noted that most of the responsibility for managing Crown consultation on AER applications rests with the Aboriginal Consultation Office ("ACO"), a specialized office housed within the Ministry of Indigenous Relations. However, the ABCA found that the matters that FMFN sought to put before the AER in relation to the MLAMP negotiations were not limited to the "adequacy of Crown consultation". The honour of the Crown can give rise to duties beyond the duty to consult.

The ABCA found that section 21 of *REDA* does not prevent the AER from considering relevant matters involving aboriginal peoples when carrying out its mandate to decide if a particular project is in the public interest. Accordingly, the ABCA concluded that the AER erred in concluding that section 21 of *REDA* prevented it from considering whether the MLAMP process was relevant to assessing whether the Project was in the public interest.

Section 7(3) of LARP

Under section 20 of *REDA*, the AER is required to "act in accordance with any applicable ALSA regional plan". The LARP is the applicable ALSA regional plan for the area where the Project is proposed. Section 7(3) of the LARP states:

> Notwithstanding subsections (1) and (2), a decision-maker or local government body must not adjourn, defer, deny, refuse, or reject any application, proceeding or decision-making process before it by reason only of
>
> > (a) the Crown's non-compliance with a provision of either the LARP Strategic Plan or LARP Implementation Plan, or
> >
> > (b) the incompletion by the Crown or any body of any direction or commitment made in a provision of either the LARP Strategic Plan or LARP Implementation Plan.

The ABCA noted that the AER interpreted s 7(3) as prohibiting it from delaying or denying approval of the Project because once finalized, MLAMP would be a LARP regional plan. However, the only mention of the MLAMP in the LARP is a statement in the "Introductory Section" that "the Moose Lake Access Management planning initiatives will be assessed for inclusion in the LARP implementation." The ABCA found that a planning initiative that will be assessed for inclusion in the LARP implementation does not fall within the scope of a "provision of either the LARP Strategic Plan or LARP Implementation Plan" so as to be subject to s 7(3). The ABCA, therefore, found that the AER failed to properly interpret s 7(3) of the LARP when it concluded that it applied to the MLAMP process.

Deferring Consideration to Cabinet

The ABCA noted that section 10(3) of *OSCA* provides that the AER may "if in its opinion it is in the public interest to do so, and with the prior authorization of the Lieutenant Governor in Council, grant an approval on any terms and conditions that the Regulator considers appropriate ".

The ABCA found that matters that fall within the scope of the "public interest", within the meaning of section 10(3) of *OSCA*, must be considered by the AER as part of its public interest mandate; the Regulator is not entitled to decline to address such matters because, in its view, they could be better addressed by Cabinet. However, the ABCA noted that this is not to say that Cabinet cannot also take such matters into account when considering whether to authorize the Project, but that does not relieve the AER of its responsibility.

The need for ultimate Cabinet approval does not provide the AER with a lawful reason to decline to consider the MLAMP negotiations and related issues insofar as they implicate the honour of the Crown.

Conclusion

The ABCA found that the AER's public interest mandate can and should encompass considerations of the effect of a project on aboriginal peoples, which in this case included the state of negotiations between the FMFN and the Crown. The ABCA held that to preclude such considerations entirely takes an unreasonably narrow view of what comprises the public interest, particularly given the direction to all government actors to foster reconciliation.

The ABCA, therefore, allowed the appeal. The ABCA directed the AER to reconsider whether approval of the Project is in the public interest after taking into consideration the honour of the Crown and the MLAMP process.

Greckol J.A. concurred with the majority that the appeal must be allowed. However, Greckol J.A. made a few additional comments by way of guidance regarding the honour of the Crown and the MLAMP negotiations.

ALBERTA ENERGY REGULATOR

Additional Information for Industry During COVID-19 Pandemic Response, AER Bulletin 2020-11

Bulletin - COVID-19 Response - Information for Industry

On April 9, 2020, the AER issued *Bulletin 2020-10: Relief for Industry During COVID-19 Pandemic Response*, explaining how two ministerial orders apply to parties regulated by the Alberta Energy Regulator.

In response to questions from stakeholders, the AER has created a webpage providing clarification and listing exemptions under these orders (Providing Information > News and Announcements > Announcements > "Relief for Industry During Covid-19 Pandemic Response"). This page will be updated as necessary.

Directive 023 (1991 Edition) and Directive 078 Rescinded, AER Bulletin 2020-09

Bulletin - Directed 023 and 078 Rescinded

As part of its contributions towards the Government of Alberta's initiatives under *the Red Tape Reduction Act*, the AER will be rescinding obsolete and redundant regulatory requirements. On April 8, 2020, the AER rescinded the following oil sands project application directives:

- *Directive 023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project* (the 1991 edition)
- *Directive 078: Regulatory Application Process for Modifications to Commercial In Situ Oil Sands Projects*

Operators are reminded that *Oil Sands Conservation Act ("OSCA")* project applications must continue to be submitted in accordance with *Draft Directive 023: Oil Sands Project Applications* (2013). The AER has used Draft Directive 023 to administer all new *OSCA* project applications since the draft was issued in 2013.

The application requirements in *Directive 078* were incorporated into *Draft Directive 023* as section 10, "Amendment Applications." Applications to modify commercial in situ projects must continue to be submitted in accordance with this section.

The application requirements under *Draft Directive 023* and processes for *OSCA* project applications have not changed. The AER has simply removed obsolete and duplicative information requirements.

New Edition of Directive 054, AER Bulletin 2020-08

Bulletin - Reporting and Surveillance - In Situ Oil Sands Schemes

On April 3, 2020, the AER released a new edition of *Directive 054: Performance Reporting and Surveillance of In Situ Oil Sands Schemes*. This edition focuses on requirements that are relevant to the current operational environment of the in situ sector. Obsolete or duplicative information requirements have been removed.

Regulatory Documents Review, AER Bulletin 2020-07

Bulletin - Regulatory Documents Review

The AER continually works to improve its regulations and processes to ensure Alberta's energy resources are developed in a manner that is responsible, safe, and efficient. As part of its contributions towards the Government of Alberta's *Red Tape Reduction Act*, the AER will be making modifications to its regulatory instruments to reduce requirements.

The AER will continue to improve the clarity of its regulatory framework by amending, deleting, or rescinding obsolete and duplicative requirements that place regulatory and administrative burden on regulated parties. These changes will not impact public safety, environmental protection, or resource conservation. Usually, updates to regulatory instruments are announced by bulletin. Given the number of instruments affected by this initiative, this bulletin is the primary announcement at this time.

Changes to regulatory instruments, including additions, amendments, and rescissions, can be viewed on the AER website, www.aer.ca > Regulating Development > Rules and Directives > Regulatory Change Report.

Relief for Industry During COVID-19 Pandemic Response, AER Bulletin 2020-10

Bulletin - COVID-19 - Industry Relief

On April 9, 2020, the AER announced that Alberta Environment and Parks and Alberta Energy have temporarily suspended a number of reporting requirements that affect Alberta's energy industry. The AER noted that physical distancing and other safety protocols put in place to support the COVID-19 response might impact the availability of industry staff and limit the capacity to comply with reporting requirements.

Alberta Energy Ministerial Order

Alberta Energy has suspended certain requirements regarding reporting of information:

- pursuant to provisions in the *Coal Conservation Rules* and approvals;
- pursuant to provisions in the *Oil and Gas Conservation Rules*, directives, approvals, licences;
- under *Directive 013: Suspension Requirements for Wells* and section 3.020 of the *Oil and Gas Conservation Rules*; and
- pursuant to provisions in the *Oil Sands Conservation Rules* and approvals for both oil sands mining and in situ.

Alberta Environment and Parks Ministerial Order

Alberta Environment and Parks has suspended requirements to report:

- information pursuant to provisions in approvals or registrations authorized under the *Environmental Protection and Enhancement Act*;
- information pursuant to provisions in licences or approvals authorized under the *Water Act*; and
- information required under a formal disposition under the *Public Lands Act*.

While certain reporting requirements have been suspended, the AER noted that this direction does not affect monitoring requirements, which must continue to be met. During the period of temporary suspensions, parties must continue to record and retain complete documentation and make it available upon request.

ALBERTA UTILITIES COMMISSION

***Alberta Electric System Operator - Decision on Preliminary Question - Application for Review of Decision 22942-D02-2019 - 2018 Independent System Operator Tariff*, AUC Decision 25086-D01-2020**

Review and Variance - ISO Tariff

In this decision, the AUC considered an application filed by the Alberta Direct Connect Consumers Association ("ADC"), the Dual Use Customers ("DUC"), and the Industrial Power Consumers Association of Alberta ("IPPCA") (collectively "DUC et al.") requesting a review and variance of specific findings in Decision 22942-D02-2019. In their application for review, the applicants alleged that the AUC made errors of law, fact or jurisdiction in the decision. The AUC denied the application.

The members of the AUC panel who authored the Alberta Electric System Operator ("AESO") tariff decision are referred to as the "Hearing Panel" and the members of the AUC panel who considered the review application are referred to as the "Review Panel."

<u>Background</u>

The Hearing Panel issued the AESO tariff decision on September 22, 2019. In the decision, the Hearing Panel:

1) accepted the AESO's 2018 updated cost causation study ("2018 Study");

2) denied the request of DUC et al. to extend waivers of the power factor deficiency charge to dual-use customers and granted the request of the AESO to grandfather the nine dual-use waivers that had been granted previously by the AESO; and

3) accepted the AESO's proposed revisions to subsections 3.2(2)(f) and 3.6(4) of its 2018 ISO tariff to provide that a customer with an industrial site will be able to choose totalized metering at a substation only if approval from the AUC that permits the export of electric energy to the Alberta Interconnected Electric System ("AIES") has been obtained.

<u>AUC's Review Process</u>

The Review Panel outlined the AUC review process under Section 10 of the *Alberta Utilities Commission Act*. It noted that the review process has two stages. In the first stage, a review panel must decide whether there are grounds to review the original decision. This is sometimes referred to as the "preliminary question." If the review panel decides that there are grounds to review the decision, the AUC moves to the second stage of the review process where the AUC holds a hearing or other proceeding to decide whether to confirm, vary, or rescind the original decision.

<u>Grounds for Review and Hearing Panel Findings</u>

DUC et al. raised three grounds in support of its review application.

(i) Cost of Service Study Update

DUC et al. argued that the approval of the 2018 update of the cost of service study, which included an update of point of delivery ("POD") capital addition costs, was not a mechanistic update using the same data as the 2014 Study. It claimed that the AESO applied for a cost of service study ("2018 Study") characterized as a mechanistic update to the 2014 cost of service study, but the POD capital additions forecasts in the 2018 Study did not utilize the same data sources, methodologies and calculation as the 2014 Study. Instead, the AESO developed and applied a new and untested methodology to forecast the POD capital additions.

(ii) Power Factor Deficiency Charge Waiver

DUC et al. submitted that the denial of additional power factor waivers to existing dual-use customers results in discriminatory tariff treatment between similar customers with and without power factor waivers. It argued that this decision would result in unjust, unreasonable, and discriminatory rates because customers with a waiver at one site will pay different tariff charges compared to a site with similar load characteristics that do not have a waiver.

(iii)Totalized Metering for Industrial Customers

DUC et al. argued that the approval of subsections 3.2(2)(f) and 3.6(4) of the proposed 2018 ISO tariff was based on these changes being proposed by the

AESO in its argument and not as part of its original application. It claimed that this was procedurally unfair because the utility customers were not given an opportunity to test the tariff provisions before they were approved.

Review Panel Findings

2018 update of the 2014 Cost Causation study

To warrant a review, the Review Panel noted that DUC et al. must demonstrate that these alleged factual errors are plainly seen or exist on a balance of probabilities and further, that the errors are material. The Review Panel found that DUC et al. had not satisfied its onus.

The Hearing Panel made the following factual determinations in its finding to approve the AESO's 2018 updated cost causation study:

- Consistency and avoiding a piecemeal attempt to alter the study are important considerations.
- Refraining from applying any assumptions not used in the 2014 study and utilizing the same data sources, methodologies, and calculation should be the goal, if practical. (Emphasis added.)
- The AESO is working with industry stakeholders as part of the Tariff Design Advisory Group to perform similar studies to those in DUC's recommendations #5 and #6. (*#6 was a recommendation that the AESO should have used the POD capital additions estimates and forecasts for every year from 2015 to 2019, as set out in an appendix to the AESO application).*
- The AESO is directed to continue the consultation process concerning the 12 CP issue, the regional tariff design, and the bulk tariff design, and to investigate and apply, if appropriate, the DUC's recommendations 1, 5, and 6 in its consultative process.
- The AESO is to incorporate any conclusions or recommendations from the consultation process on these matters in its next tariff application.

DUC et al. argued that because the AESO's 2018 study was not a mechanistic exercise using exactly the same data sources, methodologies, and calculations as the 2014 Study, the Hearing Panel erred in relying on these facts when it approved the AESO's 2018 study. However, it was clear to the Review Panel that the Hearing Panel added the words "if practical" in recognition that, although a laudable goal, it may not always be possible to do so. As well, it was clear that the Hearing Panel was aware that additional data would be required since the 2014 Study was conducted.

Concerning DUC et al.'s Recommendation #6, the Review Panel noted that it was clear that the Hearing Panel was well aware of the positions of the parties and determined, in its findings, to direct the AESO to investigate and apply, if appropriate, the DUC's Recommendation #6 in its future consultative process.

DUC et al.'s request for a review on this ground was denied.

Power Factor Deficiency Charge Waiver

The Review Panel noted that on this issue, the Hearing Panel made the following factual determinations:

- It dismissed the claim by DUC et al. that the AESO has used incorrect billing determinants in Rate Demand Transmission Service ("DTS").
- The delivery of reactive power to a POD represents an obligation for the AESO, regardless of what causes the downstream requirements for reactive power and that such costs should generally be attributed to the "causer" of the reactive power requirement.
- A DFO may address net reactive power required by introducing incentives to end-use customers or distribution connected generation ("DCG") proponents to manage their reactive power requirements or by installing reactive power devices on the electric distribution system. Granting a waiver to DCG proponents could frustrate the DFOs' ability to manage net reactive power requirements on their systems.
- It would be reasonable for the AESO to continue to grandfather the waivers for these market participants indefinitely because to do otherwise would unfairly treat market participants who relied on the AESO's prior determination to grant a waiver when making investment decisions.

The Review Panel found that the arguments made by DUC et al. in support of its review request covered ground that was already considered by the

Hearing Panel and was an attempt to reargue its position that the AESO should extend waivers.

The evidence before the Hearing Panel confirmed that the AESO has not granted a waiver since 2016 and that it had recently refused to grant a waiver. Consequently, the Review Panel found that the rationale advanced by the AESO, and accepted by the Hearing Panel, to grandfather nine sites because those customers had already made decisions and were operating in reliance on past waivers was a fair distinction to be made between past and future customers.

DUC et al. also argued that waivers must be granted because the AESO could not accurately measure the power factor deficiency charge and that the Hearing Panel erred by not providing a mechanism for these measurement errors to be mitigated in the future. The Review Panel noted that it was clear on the face of the decision that the AESO did not agree with DUC et al.'s characterization of the AESO's abilities.

Moreover, it was the AESO's evidence that the granting of a waiver is a matter of general policy. The Review Panel noted that it was reasonable to conclude that had the AESO been unable to measure power factor deficiency charges, it is unlikely that the AESO would have declined to grant waivers when requested to do so.

DUC et al.'s request for a review on this ground was denied.

Totalized Metering for Industrial Complexes

DUC et al. submitted that in the AESO's application, the AESO proposed terms and conditions in its proposed 2018 ISO tariff to allow a market participant to elect to be billed on either a gross or net-metered basis. It argued that the AESO supported this position throughout the evidentiary portion of the proceeding, including during the oral hearing, and that it was only in the AESO's argument that it proposed that customers with industrial sites would be able to choose totalized metering at a substation only if approval from the AUC had been obtained. It submitted that because most industrial customers with behind-the-fence generation are net-metered, moving a new dual-use customer to gross metering is not a simple administrative change but a significant change in the tariff. DUC et al. stated that it was procedurally unfair for the Hearing Panel to accept this change to the ISO tariff because the utility customers were not allowed to test these provisions before they were approved.

The AESO confirmed that in its amended tariff application, it proposed to continue to allow totalized (or net) metering for self-supply industrial complexes, including those that have not obtained an industrial service designation ("ISD"). However, it stated that on a subsequent review of Decision 23418-D01-2019, it determined that its proposal would be inconsistent with the AUC's findings in that decision. Therefore, to address this legal determination, the AESO indicated in argument that it would not permit totalization for self-supply industrial complexes that are not authorized to export electric energy to the AIES.

The Review Panel found that procedural fairness was afforded to DUC et al. and other proponents and that they had an opportunity to respond fully to the legal issue raised by the AESO in its argument. More specifically, the Review Panel was satisfied that DUC et al. and all parties knew or ought to have appreciated the issues attendant with totalization and the AUC's findings in Decision 23418-D01-2019 and were given a meaningful opportunity to present their cases about the legal implications arising from that decision and its application for the ISO tariff in their reply argument submissions.

Accordingly, DUC et al.'s request for a review on this ground was denied.

The application for review was dismissed.

***Alberta Electric System Operator - Request for Deferral of Payment of 2020 Interim Refundable Demand Transmission Service* Charges, AUC Decision 25508-D01-2020**

Facilities - Transmission

On March 18, 2020, the Government of Alberta announced that "Albertans who are experiencing financial hardship directly related to the COVID-19 pandemic can work with their utility company to defer electricity and natural gas bills until June 19, 2020, without any late fees or added interest payments." This payment deferral option applies to residential, farm and small commercial electricity consumers with sites that consume less than 250,000 kilowatt-hours of electricity per year and to residential, farm and small commercial natural gas consumers with sites that consume less than 2,500 gigajoules per year ("Eligible Retail Consumers"). The program is known as the Utility Payment Deferral Program.

The structure of the electricity industry in Alberta is comprised of several parties, each of whom has a role to fulfill in the delivery of electricity services to Albertans:

- Alberta Electric System Operator (”AESO”)
- Transmission Facilities Owners (“TFOs”)
- Distribution Facility Owners (“DFOs”)
- Retail Electricity Service Providers (competitive electricity retailers or regulated rate option providers)

Consequently, when an Alberta consumer elects to defer the payment of its electricity bill further to the Utility Payment Deferral Program, each of the parties with a role in the delivery of electricity services to Albertans is affected.

On April 15, 2020, the AUC received an application from the AESO requesting approval to permit the deferral of the recovery of Rate DTS charges from DFOs that would otherwise apply, as approved by the AUC in Decision 25175-D01-2020 through two proposed deferral programs: (1) Retail Consumers Deferral Program; and (2) Transmission-Connected Deferral Program. Amendments to the application were made and filed on April 21, 2020.

<u>Relief Requested by the AESO</u>

The AESO proposed two distinct programs to temporarily facilitate the deferral of the collection of certain charges determined in accordance with Rate DTS in the ISO tariff.

Retail Consumers Deferral Program

The first program, referred to as the Retail Consumers Deferral Program, would permit each DFO and the City of Medicine Hat (collectively “DFOs”) to defer payment of the following ISO tariff charges billed to a DFO as a result of Eligible Retail Consumers during the 90-day period of the Utility Payment Deferral Program, from March 18, 2020, until June 19, 2020 (“Retail Consumers Deferral Period”), and any extension (“Extended Transmission-Connected Deferral Period”), if such charges are not paid by a Retail Electricity Service Provider to the DFO:

(a) Charges determined under Rate DTS in respect of the transmission of electric energy consumed by Eligible Retail Consumers; and

(b) Charges applied under Rider C, Deferral Account Adjustment Factor, of the ISO tariff (Rider C), and Rider F, Balancing Pool Consumer Allocation Rider, of the ISO tariff (Rider F).

The AESO made several specific requests for relief in support of its Retail Consumers Deferral Program.

Transmission-Connected Deferral Program

The AESO indicated that its proposed Transmission-Connected Deferral Program would apply to:

(a) persons who have entered into an arrangement directly with the AESO for the provision of system access service under subsection 101(2) of the *Electric Utilities Act*;

(b) the legal owners of industrial systems that have been designated as such by the AUC; and

(c) the City of Medicine Hat.

(collectively, “Transmission-Connected Market Participants”).

The AESO proposed that under the Transmission-Connected Deferral Program, Transmission Market-Connected Participants would be able to defer payment of any increase in their charge determined by the AESO from Rate DTS in place before April 1, 2020, to the interim Rate DTS approved in Decision 25175-D01-2020 or any final Rate DTS approved in an AESO tariff decision during the period April 1, 2020, to June 30, 2020 (“Transmission-Connected Deferral Period”) or during the period of any extension to the Transmission-Connected Deferral Period (“Extended Transmission-Connected Deferral Period”).

The AESO made several specific requests for relief in support of its Transmission-Connected Deferral Program.

<u>AUC Findings</u>

Discretion to Issue a Decision Without Notice or Hearing

The AUC found that no party would be directly and adversely affected by granting the requested relief. Notwithstanding this finding, the AUC issued a filing announcement and provided notice to parties registered in Proceeding 25175 of this application. As well, although no formal process was established, AUC staff heard brief oral submissions from the AESO, and the DFOs on April 20, 2020, regarding the application and the AESO's amended application reflected these submissions.

Authority to Grant Relief

Section 8(2) of the *Alberta Utility Commission Act* grants the AUC broad authority in the exercise of its powers, while section 23(1) grants the AUC further general powers to order persons to do (or cease to do) any act matter or thing under AUC jurisdiction.

The AUC found that its mandate is sufficiently broad to confer jurisdiction to grant the AESO's requested relief if the AUC determined that doing so is within the public interest.

Public Interest to Grant Relief

Given the complex electricity industry structure, a substantive change to the functioning of one element necessarily has a domino effect on the other entities who are charged with a role in the delivery and billing of electricity to Albertans. Although the AESO's proposal will lead to an increase in tracking and reporting activity for certain affected market participants, the AUC considered that this activity will be manageable and will not result in a significant cost burden given the information regularly provided in tariff bill files. Further, if DFOs incur additional costs to facilitate the relief proposed, namely, that the AESO carry the costs of the DTS charges of the electricity bills of Eligible Retail Consumers who have opted to defer payment of their electricity bills under the Utility Payment Deferral Program, these DFOs may apply to the AUC for recovery of their tracking and reporting costs as a Y factor adjustment.

Moreover, the AUC noted the proposed deferral programs are conceptually aligned with the Utility Payment Deferral Program and have been brought forward in response to the direction of the Alberta Department of Energy as part of the Government of Alberta's efforts to address financial hardships affecting Albertans as a consequence of the COVID-19 pandemic.

The AUC considered it to be in the public interest to approve the establishment of the two proposed deferral programs.

Process for Recovery of Deferred Payments by the AESO

The AESO will be required to collect the DTS, Rider C, and Rider F charges that are not paid by a Retail Electricity Service Provider to a DFO and the deferred portion of the Rate DTS charges of Transmission-Connected Market Participants at some future point. Under this requirement, the AESO will be authorized to create any deferral accounts as part of the implementation of the relief requested in the application.

The AESO has the authority to recover these revenue shortfalls through a rate rider or riders to its ISO tariff. Any proposal to collect amounts that may be accrued to the above-noted deferral accounts as a consequence of this decision and to be recovered through a rate rider shall be set out in an application from the AESO to be filed for approval by the AUC.

Order

The AUC granted the AESO the relief to temporarily facilitate the deferral of the collection of certain charges determined under Rate DTS in the ISO tariff, to enable the Retail Consumers Deferral Program and the Transmission-Connected Deferral Program.

AUC Announcement - *Update on the impact of COVID-19,* April 17, 2020
Announcement - COVID-19 Impact

The AUC issued an announcement regarding the impact of COVID-19. It noted that AUC staff are working from home for the foreseeable future, and using technology to host internal meetings and have eliminated travel.

The AUC noted that it is mindful of the limits stakeholders have and the extraordinary challenges they are facing in these circumstances. The AUC is looking at its approach to regulation during this period and has assumed a more flexible approach to regulation, including a pragmatic approach to compliance. For example, it has deferred compliance filings, suspended specified penalties for self-reported contraventions, and supported the Market Surveillance Administrator in adopting a flexible approach for market participants.

The AUC is also examining its approach to its 2020-2021 Operational Plan objectives and initiatives. Many of those activities are outward-facing and require the involvement of stakeholders through meetings and consultations. As a result, the AUC is examining how it can advance this agenda while being mindful of competing priorities, including exploring whether and how it can apply technology to AUC consultations and hearings.

For the moment, the AUC has delayed publication of its operational plan, which it had intended to post at the beginning of the fiscal year, while it considers how best to deliver on that agenda. The AUC will continue to provide updates on its approach through its website and in periodic updates.

AUC Bulletin 2020-13 - *Interim Changes to AUC Participation Involvement Program and Related Information Requirements*

Bulletin - Participant Involvement Program

The AUC is implementing steps to mitigate the risk of COVID-19 to protect its stakeholders, its employees, and its work critical to Alberta's essential utility services. As part of these efforts, the AUC is making adjustments to its participant involvement program ("PIP") requirements for electric and gas facility applications. These adjustments are intended to clarify PIP requirements until things change with respect to COVID-19.

Participant Involvement Programs

Appendix A1 of *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* sets out the AUC's PIP guidelines for power plant, transmission, and industrial system designation projects. Appendix A2 sets out PIP guidelines for independent system operator needs identification document applications. PIP requirements for gas utility pipeline applications are set out in Section 2 of Rule 020: Rules Respecting Gas Utility Pipelines.

The principles of effective PIPs and the related information requirements set out in appendixes A1 and A2 of Rule 007 and in Section 2 of Rule 020 continue to apply subject to the following two important adjustments.

First, currently Rule 007 and Rule 020 state that applicants must give stakeholders a minimum of 14 calendar days to receive, consider, and respond to project notifications. Effective immediately, and until further notice, project proponents must give stakeholders a minimum of 30 days to receive, consider, and respond to project notifications. The Commission considers this additional time to be reasonable in the current circumstances.

Second, Rule 007 and Rule 020 both promote face-to-face consultation. Given the COVID-19 crisis and the ongoing need to practice physical distancing, face-to-face consultation is discouraged unless it can be undertaken in compliance with physical distancing practices. Further, while there is no requirement in Rule 007 to hold meetings, it discusses the use of open houses or town hall type meetings as components of a PIP. In the current circumstances, applicants should not hold public open houses or town hall meetings.

While Rule 007 and Rule 020 encourage face-to-face consultation where possible, both also recognize the validity of other means of communication for consultation purposes. This could include phone, email, video conferencing, etc. The Commission encourages applicants to employ these alternative forms of communication wherever possible.

The Commission recognizes that these adjustments may affect a project's schedule; however, the Commission considers the adjustments to be reasonable given the circumstances. The Commission also acknowledges that most, if not all, applicants have recently made the necessary modifications to their PIP practices in response to the ongoing COVID-19 crisis.

Indigenous Engagement

The Commission is aware that a number of Indigenous consultation offices have closed or are working at reduced capacity as their staff work from home (or remotely) with varying access to technology and the internet.

Applicants should continue to reach out to Indigenous groups to understand their community's unique circumstances and availability to discuss proposed electric and gas utility facilities under Rule 007 and Rule 020. However, applicants must keep in mind that it may be challenging for consultation contacts to engage community members and leadership at this time. The Commission encourages applicants to be sensitive to the capacity challenges of Indigenous groups and to build additional time into their participant involvement programs, where possible.

Mailing Labels for Issuing Notices

A requirement for facility applications is the provision of mailing labels for stakeholders contacted by a proponent as part of its PIP.

Effective immediately, and until further notice, project proponents are no longer required to provide printed mailing labels. Instead, proponents must file an Excel spreadsheet with their application that lists stakeholder contact information with columns for name, company name, address 1, address 2, city, province, postal code, and country.

AUC Bulletin 2020-14 - *Stakeholder Comments Sought on Suggested Updates to AUC Rule 027 Penalty Table*

Bulletin - Rule 027

On January 31, 2020, the Alberta Utilities Commission released Bulletin 2020-03 announcing a consultation with stakeholders to review AUC Rule 027: *Specified Penalties for Contravention of Reliability Standards*, to update the content of the penalty tables to reflect the current version of the Alberta reliability standards and to consider proposed changes from market participants. Comments on these changes were submitted by February 29, 2020.

The majority of the received comments were focused on the proposed changes from the Market Surveillance Administrator and not on the placement of the new and revised reliability standards in the penalty table.

Due to the challenges presented by the COVID-19 pandemic, the Commission has not yet responded to all stakeholder comments and, at this time, will be focusing on updates to the placement of new and revised reliability standards in the penalty table. In the interest of maintaining an up-to-date rule, with a record of all currently applicable reliability standards, the Commission is now soliciting comments from stakeholders on the new reliability standard classifications in the penalty table.

In its initial penalty table placements, the Commission considered the existing placement of similar reliability standards in Rule 027 and the experience of the North American Electric Reliability Corporation in enforcing compliance with its comparable reliability standards.

Should you believe any of the reliability standards or requirements need to be placed in a different penalty table than what is proposed, the Commission requests that you share your reasoning by Tuesday, April 21, 2020.

AUC Bulletin 2020-15 - *Reducing Regulatory Burden: Checklist Application Pilot Project for Low-risk Electric Transmission and Gas Utility Pipeline Applications*

Bulletin - Pilot Project

The AUC is introducing a pilot project to assess the effectiveness of reduced application requirements for the following facility application types:

Electric Transmission Facilities

- Letters of enquiry for minor substation alterations.
- Letters of enquiry for minor transmission line alterations.
- Time extensions for transmission facilities.

Gas Utility Pipelines – Tier 1 Applications

- Record amendments.
- Self-disclosures.
- Pipeline splits due to as-built review.
- Abandonment applications filed within 90 days of completing the abandonment operation.
- Low-pressure conversions.
- Maximum operating pressure changes.
- Surface pipeline removals.
- Pipeline splits and abandonments requested and paid for by a third party.

For the application types listed above, applicants are currently required to file an application and all supporting documents such as environmental evaluations, participant involvement program summaries, etc. Depending upon the application, this can include multiple documents.

During the pilot project, applicants will only be required to file a single-page checklist confirming that the regulatory requirements for the application have been met and, in some cases, a draft of the amended approval or licence they are requesting. Applicants will not be required to file any other related supporting documents. Applicants will be required to keep on file the related supporting documents as they may be required to respond to an AUC audit request. The AUC intends to audit between 10 and 15 percent of applications to assess compliance.

The goals of this pilot project are to reduce the regulatory burden and maintain the effectiveness and credibility of the regulatory system.

Next Steps for Applicants

The AUC has prepared forms for the checklist applications and accompanying instructional documents for completing the forms. Applicants can use the new checklist approach effective immediately.

Assessment of Effectiveness

The AUC will evaluate the effectiveness of this pilot project over the next 12 months. The AUC will also assess over that time whether to develop specified penalties for any non-compliance identified in post-approval audits.

***AltaLink Investment Management Ltd. - Application for 2020 Debt* Issuance, AUC Decision 25455-D01-2020**

Public Utilities Act, Section 101

In this decision, the AUC considered the application of AltaLink Investment Management Ltd. ("AIML"), in its capacity as the general partner of AltaLink Investments, L.P. ("AILP"), to cause AILP, to offer, issue and sell senior, unsecured bonds or other debt securities in the aggregate principal amount of up to $300 million prior to November 1, 2020. The AUC approved the application.

Introduction

On March 13, 2020, AIML, as the general partner of AILP, applied with the AUC, under Section 101 of the *Public Utilities Act*, to cause AILP to offer, issue and sell senior, unsecured bonds or other debt securities (collectively, "Debt Securities") in the aggregate principal amount of up to $300 million prior to November 1, 2020.

Background

In Decision 21555-D01-2016, the AUC approved Rule 031, which provides guidance to the application of a conditional exemption from the requirement to seek advance AUC approval for issuances of equities and long-term debt, and an exemption from certain operational reporting requirements. Section 3 of Rule 031 exempts a number of securities transactions from advance AUC approval. Section 3.4 states that if an issuance does not qualify for exemption under this rule, the designated owner must seek advance AUC approval for the issuance by way of a formal application.

Accordingly, should a debt or equity issuance not qualify for the exemption under Rule 031, the designated utility owner must seek approval of its securities transaction under section 101(2) of the *Public Utilities Act*.

Details of the Application

The AUC noted that AIML plans to cause AILP to offer, issue, and sell Debt Securities in the aggregate principal amount of up to $300 million prior to November 1, 2020.

AUC Findings

The AUC noted that AIML and AILP do not qualify for an exemption under section 3.1 of Rule 031. Consequently, AIML is required to obtain approval from the AUC, under section 101(2) of the *Public Utilities Act*, before issuing any bonds or other evidence of indebtedness for terms greater than one year.

Section 101(2)(a)(ii) of the *Public Utilities Act* requires that the AUC determine (a) whether the proposed issuance is to be made in accordance with law; and (b) whether the AUC is satisfied regarding the purposes of the proposed debt issuance described in the application.

Based on the opinion provided by AIML's legal counsel, Borden Ladner Gervais LLP, dated March 11, 2020, the AUC was satisfied that due diligence was being exercised and steps have been taken to ensure that the issuance will be made in accordance with law.

The AUC accepted AIML's submitted purposes of the issuance and was satisfied that the level of detail provided in the application is consistent with similar applications made by other AUC regulated utilities that are required to obtain approval of proposed debt issuances.

The AUC concurred with AIML's assessment that approval of AIML's debt issuances does not inhibit the AUC from conducting a detailed examination of the prudence of AIML's debt issuances in future general tariff applications or related proceedings. The onus still resides with AIML to demonstrate that actual debt issuance was obtained prudently and that the costs, term, and other matters are consistent with the public interest and operation of a public utility.

The AUC reviewed the current application and found that the proposed debt issue appears to be in the public interest for the purposes of financing assets or activities in the operation of the public utility.

The AUC found that the requirements of section 101(2)(a)(ii) of the *Public Utilities Act* were met and approved the debt issuance of AIML, in its capacity as the general partner of AILP, in the aggregate principal amount of up to $300 million, and the proposed purposes of the debt issuance.

***AltaLink Management Ltd. - Application for 2020 Debt* Issuance, AUC Decision 25454-D01-2020**

Public Utilities Act, Section 101

In this decision, the AUC considered the application of AltaLink Management Ltd. ("AML") in its capacity as the general partner of AltaLink, L.P., ("ALP") to cause ALP, to offer, issue and sell medium-term notes or other debt securities in the aggregate principal amount of up to $500 million prior to December 1, 2020. The AUC approved the application.

Introduction

On March 13, 2020, AML, as the general partner of ALP, filed a debt application with the AUC seeking approval, under Section 101 of the *Public Utilities Act*, to cause ALP to offer, issue and sell medium-term notes or other debt securities in the aggregate principal amount of up to $500 million prior to December 1, 2020.

Background

In Decision 21555-D01-2016, the AUC approved Rule 031, which provides guidance to the application of a conditional exemption from the requirement to seek advance AUC approval for issuances of equities and long-term debt, and an exemption from certain operational reporting requirements. Section 3 of Rule 031 exempts a number of securities transactions from advance AUC approval. Section 3.4 states that if an issuance does not qualify for exemption under this rule, the designated owner must seek advance AUC approval for the issuance by way of a formal application.

Accordingly, should a debt or equity issuance not qualify for the exemption under Rule 031, the designated utility owner must seek approval of its securities transaction under section 101(2) of the *Public Utilities Act.*

Details of the Application

The AUC noted that AML plans to cause ALP to offer, issue, and sell debt securities in the aggregate principal amount of up to $500 million prior to December 1, 2020.

AUC Findings

The AUC noted that AML and ALP do not qualify for an exemption under section 3.1 of Rule 031. Consequently, AML is required to obtain approval, under section 101(2) of the *Public Utilities Act*, from the AUC before issuing any bonds or other evidence of indebtedness for terms greater than one year.

Section 101(2)(a)(ii) of the *Public Utilities Act* requires that the AUC determine (a) whether the proposed issuance is to be made in accordance with law; and (b) whether the AUC is satisfied regarding the purposes of the proposed debt issuance described in the application.

Based on the opinion provided by ALP's and AML's legal counsel, Borden Ladner Gervais LLP, dated March 11, 2020, the AUC was satisfied that due diligence is being exercised and steps have been taken to ensure that the issuance will be made in accordance with law.

The AUC reviewed AML's identified purposes of the issuances and was satisfied that the level of detail provided is consistent with similar applications made by other AUC regulated utilities concerning proposed debt issuances. The AUC noted that AML stated that the final amount issued would be partly determined by matters considered in the DFO Customer Contribution Plan (Proceeding 24932).

Section 101(2)(d) of the *Public Utilities Act* requires AML to receive approval from the AUC to encumber its property, franchises, privileges or rights, or any part of them. As detailed in its "Preliminary Term Sheet," assets are pledged as security to AML's planned debt issuance.

In a letter submitted in Proceeding 21555, AML stated that "AltaLink does not plan to issue unsecured debt or bank credit facilities due to secured debt attracting investors and decreasing the costs of borrowing as compared to unsecured debt. This allows AltaLink to ensure it passes on just and reasonable rates to the ratepayer."

For this application, the AUC found the rationale to issue secured debt to be reasonable.

In addition, the AUC found that the credit rating related information provided by AML with the application was satisfactory for purposes of the application and provided reasonable assurance that the proposed issuance of Debt Securities should not have a material adverse effect on the cost of other debt recovered through AML's revenue requirement.

The AUC concurred with AML's assessment that approval of AML's debt issuances would not inhibit the AUC from conducting a detailed examination of the prudence of AML's debt issuances in future general tariff applications or related proceedings. The onus still resides with AML to demonstrate that actual debt issuance was obtained prudently and that the costs, term, and other matters are consistent with the public interest and operation of a public utility.

Concerning the current application, the AUC considered that the proposed debt issue is required for the purposes of financing assets or activities for the operation of the public utility and is, therefore, in the public interest.

Given the above, the AUC found that AML complied with the requirements of section 101(2)(a)(ii) and has suitable justification to pledge assets as security to the planned debt issuance for section 101(2)(d)(i) of the *Public Utilities Act* and therefore approved AML's 2020 second debt application as filed.

ATCO Electric Ltd. - 2019 Distribution Tariff Phase II **Application, AUC Decision 24747-D01-2020**

Rates - Distribution

<u>Decision Summary</u>

In this decision, the AUC addressed the 2019 distribution tariff Phase II application filed by ATCO Electric Ltd. ("ATCO Electric"). For the reasons set out in this decision, the AUC approved:

- The methodology and allocation of transmission system access service costs as filed;
- The methodology and allocation of distribution service costs, including the classification ratios as applied for; the brushing study, subject to the correction of an error made in the brushing costs allocator; the account services and public information costs study; and the wholesale billing study, subject to an update of IT costs;
- The methodology used to allocate Rural Electrification Association ("REA") acquisition costs;
- The 2017 billing determinant forecast to establish the rates for each rate class and the methodology proposed to adjust rates through to the applicable year of implementation;
- The proposed changes to revenue-to-cost ratios, as filed;
- Rate structures for existing rates, as filed;
- The proposed changes to existing price schedules;
- The new Time-of-Use Residential service rate D13, the new Small Technology rate D22 and the new Electric Vehicle (EV) Fast-Charging Service rate D23, except for a minor revision to the D22 price schedule;
- Proposed terms and conditions ("T&Cs") of service, except for certain sections in the customer T&Cs related to exit costs, easements and rejection of an application for service; and
- A no-notice proceeding process for maintenance multiplier applications.

The AUC denied the new Low-Use Residential service rate D12. The AUC also determined that ATCO Electric does not need to continue to improve its feeder analysis. Finally, the AUC rejected arguments from the Alberta Federation of Rural Electrification Association ("AFREA") that utility asset disposition ("UAD") issues were triggered by the application.

<u>Overview of ATCO Electric's Application</u>

In its application, ATCO Electric provided a distribution 2017 cost of service study ("COSS") and corresponding tariff design, based on cost data prior to 2018 ("2017 Data") as instructed in previous AUC decisions. It also provided a COSS and corresponding rate design for transmission access payments, also in accordance with previously approved methodologies.

<u>Cost of Service Studies</u>

The AUC noted that ATCO Electric's distribution tariff is composed of three components: a transmission component, a distribution component and a service component. Each of these cost components is allocated to rate classes separately based on distinct transmission and distribution cost drivers and characteristics.

Transmission System Access Service Costs

The AUC reviewed the transmission 2017 COSS schedules and load research study provided in the application and found them consistent with the methodology approved in previous ATCO Electric Phase II decisions. The AUC approved ATCO Electric's methodology and allocation of transmission system access service ("SAS") costs, as filed.

Distribution Cost of Service Studies

ATCO Electric submitted that the distribution cost allocation methodology used in this application was the same methodology used in its previous Phase II applications. As part of the application, ATCO Electric updated its distribution cost of service studies, including its classification factors study, brushing study, account services and public information study and wholesale billing study.

The AUC approved the classification ratios as applied for, including the poles, towers and fixtures customer classification ratio of 55 percent.

With the exception of an error made by ATCO Electric in the brushing costs allocator, the AUC found that the update to the brushing study followed the currently approved methodology, reasonably derived the cost allocators for ATCO Electric's rate classes. Accordingly, the study was approved.

The AUC approved the account services and public information costs study, as filed. The AUC also approved the wholesale billing study, subject to adjustments required due to ongoing proceedings.

Feeder Analysis

A feeder analysis is an alternative to the traditional COSS methodology that consists of allocating costs to customers based on infrastructure information related to the distribution system. The basic methodology of the feeder analysis involves line length data captured for each customer on a specific point of delivery ("POD") feeder for a sample of POD feeders. The data quantifies the amount of line length that is attributable to each customer and the amount of line length that is shared by the various customers residing on a POD feeder.

ATCO Electric stated that it has more confidence in its currently approved traditional COSS methodology and, therefore, will not be pursuing the implementation of a feeder analysis. Although the AUC acknowledged that a feeder analysis might be superior to a traditional COSS, it noted the concerns of ATCO Electric regarding the costs that would be incurred to improve the results of its feeder analysis.

As part of the Distribution System Inquiry and any related proceedings arising from the inquiry, the AUC expected that alternative Phase II approaches and the associated costs will be explored. Therefore, the AUC considered it premature to direct ATCO Electric to pursue its feeder analysis at this time.

<u>Load Forecast</u>

Based on its review and assessment of ATCO Electric's load forecast methodology, the AUC found the methodology and resulting 2017 forecast billing determinants reasonable.

<u>Rate Design</u>

Revenue-to-cost Ratios

ATCO Electric proposed to increase the revenue-to-cost ratio for the customer (fixed) component of most of its rates to recognize the fixed nature of its costs and move towards collecting revenue based on cost causation through a fixed fee.

The AUC observed that the proposed changes to revenue-to-cost ratios were generally within three percent of those approved in the last Phase II decision and agreed with ATCO Electric that gradual changes to its revenue-to-cost ratios are required to mitigate potential rate shock from an intra-class perspective. The AUC approved the changes to ATCO Electric's revenue-to-cost ratios, as filed.

Price Schedules

The AUC agreed that it was reasonable to retain the existing rate structure for all of ATCO Electric's existing rates. Accordingly, the AUC approved

ATCO Electric's rate structure, as filed, except for the proposed rate for low-use residential customers.

Allocation of REA Acquisition Costs

The AUC found the methodology used by ATCO Electric to allocate REA acquisition costs in its Phase II application was reasonable.

ATCO Electric's SAS Rate Design

The Canada West Ski Areas Association ("CWSAA") raised an issue with ATCO Electric's SAS rate design specific to the incorporation of the AESO's bulk transmission charges into ATCO Electric's rates. The CWSAA explained that the AESO's bulk transmission charge has no demand ratchet, while ATCO Electric applies a demand ratchet to the transmission component of its rates. The CWSAA recommended that for certain rates, ATCO Electric should be directed to flow through the AESO DTS bulk transmission charge on an unratcheted basis, consistent with the AESO DTS tariff.

Due to the potential for changes to the AESO tariff design in the near future and the concern with intra-class rate effects, the AUC denied the CWSAA proposal. In addition, the AUC noted that there might be related ongoing discussions in the Distribution System Inquiry, and any related proceedings arising from the inquiry could inform the AUC on SAS rate design specific to the incorporation of the AESO's bulk transmission charges.

New Rate Classes - D12 – Low-Use Residential

ATCO Electric proposed a new residential rate to address the different load profiles and consumption patterns associated with low-use residential customers. ATCO Electric explained that the fixed portion of a customer's bill is relatively high for low-use customers and, therefore, it designed the low-use residential rate with a lower fixed charge and a higher energy charge than its existing residential rate, D11.

The AUC was not convinced that a new rate for low-use customers is warranted at this time. Absent further analysis that demonstrates low-use residential customers cause lower fixed costs, the AUC found that the stratification proposed in rate D12 may not be consistent with cost causation.

D13 – Time-of-Use Residential Rate Class

ATCO Electric proposed a time-of-use residential rate that would be available to customers in the Grande Prairie region, where it plans to install approximately 2,000 Advanced Metering Infrastructure ("AMI") meters, as a pilot program. ATCO Electric expected that the rate would help shift and reduce the overall distribution system peak, thereby increasing system stability. ATCO Electric's Time-of-Use Residential Service rate - D13 was approved, as filed.

D22 – Small Technology Rate Class

ATCO Electric stated that the small technology rate class would be available to customers who provide technology-related services, have a monthly average demand that is less than 1 kW, and have predictable loads and end-use characteristics. This rate is designed for sites like street crossings, crosswalks, signs, cable boosters, digital carriers, Wi-Fi devices, LED signs, 5G networks, and other small technology types. The AUC approved the rate class as filed.

D23 – EV Fast-Charging Service Rate Class

ATCO Electric proposed a new rate, Price Schedule D23, for EV fast-charging service, which would be limited in availability pending any AUC approvals or directions from the Distribution System Inquiry. The AUC approved the new rate, on a pilot basis.

Distribution Bill Impact

The AUC observed that the increases and decreases to customer bills are not expected to exceed 10 percent for any of the rate classes, except for the street light rate class, D61. The AUC found that a greater than 10 percent change was reasonable for this rate class.

<u>Incorporating the 2019 Phase II Results in Rates Under Performance-based Regulation</u>

The AUC reviewed the schedules and calculations used to determine ATCO Electric's proposed 2019 performance-based regulation ("PBR") rates and found the methodology adequately reflects AUC determinations in earlier decisions. The AUC approved the methodology proposed by ATCO Electric to adjust its rates through to the applicable year of implementation.

Terms and Conditions for Electric Distribution Service

The AUC reviewed the proposed revisions to customer T&Cs and found that other than the sections regarding Payment in Lieu of Notice ("PILON") and customer exit provisions; section 6.1, Easements; and section 4.4, Rejection of Application; the revisions provided clarity and consistency of terms in the customer T&Cs.

Other Matters

Maintenance Multiplier Process

The AUC approved a no-notice proceeding process for the maintenance multiplier application process for high-pressure sodium to LED streetlight fixture conversions submitted by ATCO Electric after April 30, 2020.

Rider E – Facilities Charge Agreements

The AUC noted that Rider E services are the result of contractual negotiations between ATCO Electric and individual customers that are subject to a customized set of pricing arrangements as well as T&Cs of service. The AUC agreed with ATCO Electric that Rider E should not form part of ATCO Electric's AUC approved rates, and amending contractual arrangements with Rider E customers as an unregulated service should continue.

The AUC noted that it expects ATCO Electric to execute any contractual amendments to remove the remaining customer services from regulated service under Rider E by December 31, 2021.

UAD Issues Raised by AFREA

The AFREA raised two matters that it considered triggered UAD issues. The AUC rejected AFREA's submissions that UAD issues were triggered.

***ATCO Electric Ltd. - Transmission Line 7L65 Rebuild* Project, AUC Decision 24102 -D01-2020**
Facilities - Transmission

In this decision, the AUC considered applications from ATCO Electric Ltd. ("ATCO Electric") to construct a new single-circuit 144-kilovolt transmission line, designated as transmission lines 7L134 and 7L65, and to salvage the existing Transmission Line 7L65, located in the Vegreville and Vermilion areas. ATCO Electric proposed a preferred route along with several segments designated as alternate routes.

The AUC found that approval of the preferred route with the alternate route segment from A55 to X56 is in the public interest.

Applications Before the AUC

ATCO Electric applied to the AUC, pursuant to sections 14, 15 and 21 of the *Hydro and Electric Energy Act*, requesting approval to:

- Construct approximately 22 kilometres of single-circuit 144-kilovolt (kV) transmission line, designated as Transmission Line 7L134;
- Construct approximately 77 kilometres of single-circuit 144-kV transmission line, designated as Transmission Line 7L65;
- Alter the approved but not yet constructed Transmission Line 7LA65;
- Alter existing Transmission Line 7L129; and
- Decommission and remove all structures of the existing 144-kV Transmission Line 7L65 that are not required to remain as part of the new 7L65 and 7L134 transmission lines ("the Project").

The Project would occur in three phases, commencing in 2020 and continuing until 2025. ATCO Electric estimated the cost at $71,519,071.

Process

The AUC received statements of intent to participate from numerous parties, including from persons who own or occupy land near the Project area and from three rural electrification associations; Braes REA, Claysmore REA and Lakeland Rural Electrification Association Limited ("Lakeland REA"). A number of the landowners joined together to form the TWP510 - ZL65 Land Owner's Group ("TZLG").

Legislative Scheme

The AUC considered these applications having regard to the applicable legislative and regulatory frameworks. In particular, these applications were assessed under sections 14, 15 and 21 of the *Hydro and Electric Energy Act* (*"HEEA"*), as well as Section 17 of the *Alberta Utilities Commission Act,* which describes the AUC's public interest mandate.

The AUC also considered Section 18 of *HEEA* and, in particular, subsection 18(2)(d). Relevant portions of section 18 state [emphasis added]:

Connections

> 18(1) The owner or operator of a power plant, transmission line or electric distribution system shall not connect that power plant, transmission line or electric distribution system, or cause or permit it to be connected,
>
> (a) to any other power plant, transmission line or electric distribution system, unless the connection is in accordance with an order under this section…
>
> (2) The Commission, either on its own initiative or on application or complaint in writing, may, with the authorization of the Lieutenant Governor in Council and by order in writing directed to the owner of a power plant, transmission line or electric distribution system,
>
> ….
>
> (**d) require the owner to share and participate or otherwise combine its interests for the transmission or distribution of electric energy with any other owner of a transmission line or electric distribution system,**
>
> and may prescribe any terms and conditions the Commission considers suitable.

Subsection 18(2)(d) of *HEEA*

On November 1, 2019, ATCO Electric filed an amendment that proposed a new preferred route segment to address concerns of nearby landowners and the Braes and Claysmore REAs.

The amendment also sought an order pursuant to subsection 18(2)(d) of *HEEA* directing the combining and sharing of ATCO Electric's transmission assets for the project with the distribution assets of Lakeland REA should the AUC approve specific route segments. Specifically, ATCO Electric indicated that certain segments of the route would require that distribution lines owned by Lakeland REA be salvaged, and a new REA distribution conductor be understrung on the proposed transmission structures.

Interpretation of "Share and Participate or Otherwise Combine" in Subsection 18(2)(d) of HEEA

The AUC noted that ATCO Electric's application amendment seeking an order under subsection 18(2)(d) of the *HEEA* turned on the interpretation of "share and participate or otherwise combine" as it is applied in this section. ATCO Electric took the position that the words "connect" and "connection" have been purposely omitted from this subsection and that this indicates the legislature's intent for this section to apply more broadly than just to connections.

When reading the phrase "share and participate or otherwise combine" in the context of section 18, and in harmony with the scheme and object of the act, it was the AUC's view that the legislature did not intend "share and participate or otherwise combine" to replace "connect" or "connection," but rather intended subsection 18(2)(d) to capture the combining of interests that are required or necessary as a result of the connections being approved (or suspended) pursuant to subsections 18(2)(a), (b) and (c).

The AUC found that subsection 18(2)(d) of *HEEA* does not apply to, or permit, the issuance of an order by the AUC directing the understringing of Lakeland REA's distribution facilities on ATCO Electric's transmission facilities.

Procedural Matters

During the oral hearing, counsel for ATCO Electric objected to the direct evidence of Lakeland REA and the TZLG witnesses, stating that the purpose of a direct evidence panel is not to provide rebuttal to witnesses that preceded them in the hearing. The AUC made oral rulings on this during the hearing but addressed this issue in its decision to further clarify the latitude a witness has during direct examination; more specifically, the AUC's interpretation of the procedure in section 42.2 of Rule 001 with respect to direct evidence.

The AUC ruled on two objections during the hearing, including an objection regarding testimony from lay witnesses and later, testimony from an expert. It allowed the lay witnesses to proceed, and asked counsel for ATCO to consider whether it would require additional time before cross-examination, or if it wished to request an oral rebuttal panel. With the expert witness, the AUC ruled that it would hold such witnesses to a higher standard.

The AUC noted that it should not be the expectation that it will grant leeway to any party. For clarity, the AUC stressed that a witness's testimony:

- Should provide a high-level summary of the party's evidence and the conclusions the party has drawn from that evidence as reflected in its previously filed direct evidence.
- Must be provided in a manner that is procedurally fair to all parties.
- Should not contain new evidence, nor should it be used as a platform to rebut the written evidence of other parties or the testimony of witnesses that have preceded them in the proceeding, except to the extent that such rebuttal is already set out in their pre-filed evidence.

Consultation

The AUC found that ATCO Electric's participant involvement program met the requirements of Rule 007.

Landowner Impacts

Health and the Effects of Electromagnetic Fields

The AUC found that the evidence before it did not support a conclusion that the Electromagnetic Fields ("EMF") from the transmission line will result in adverse health effects.

Property Value, Visual, Noise, and Other Impacts

The AUC found that general impacts raised by interveners were not significant and further that if they do occur, they are likely to occur on both the preferred and alternate routes, and so do not provide a rationale for selecting one over the other.

The AUC found that the removal of a large percentage of 50-year-old trees that formed a shelterbelt on the property of one of the interveners was a distinct impact and noted it would consider it when assessing which route, if any, is in the public interest.

Agriculture Impacts

The AUC noted that many landowners in this area already experience agricultural impacts from the existing transmission line. Rebuilding Transmission Line 7L65 will generally result in increased clearances and reduced land usage as a result of a move from H-frame structures to monopole structures and from a largely midfield location to one more consistently within road allowances. The AUC found that these factors all result in a net reduction of agricultural impacts.

The AUC also noted that the transmission line will comply with the Alberta Electrical Utility Code, that clearances will be generally increased from that of the existing transmission line and distribution lines, and that ATCO Electric has committed to consulting with stakeholders about the height of conductors and location of structures. The AUC was satisfied that the design of the project and mitigations proposed sufficiently address the issue of clearances.

The AUC found ATCO Electric's practices and procedures to reduce the spread of soil-borne diseases, and noxious weeds were reasonable.

The AUC noted that it expects that ATCO Electric will comply with the practices and procedures within its Environmental Protection Plan ("EPP"). Further, the AUC expects that ATCO Electric will ensure that its employees, contractors, and subcontractors conduct themselves in a manner that contributes toward a positive and trusting relationship with stakeholders.

Impacts to Rural Electrification Associations

Lakeland REA requested that the AUC impose several conditions if the Project was approved. The AUC found that the conditions requested by Lakeland REA were either not necessary, not reasonable, or not in the public interest. The AUC noted that ATCO Electric made a number of commitments or communicated information regarding its practices in response to the requested conditions. In general, the AUC found ATCO Electric's responses to be reasonable and did not consider it necessary to enshrine these commitments or practices in the form of conditions.

Environmental Impacts

The AUC found that with the proper implementation of the mitigation measures proposed in ATCO Electric's EPP, the environmental effects of the Project will be minimal.

Routing

The AUC approved the preferred route proposed by ATCO Electric, with one alternate route segment.

With regard to the concerns raised by Lakeland REA, the AUC did not consider these impacts so significant that they warranted choosing the alternate route segment or not approving the preferred route. The AUC's approval of the preferred route in this segment will require that the distribution be either understrung or relocated. While the AUC considered that understringing would result in lower impacts, it did not consider that it has the authority under subsection 18(2)(d) of *HEEA* to order Lakeland REA to understring its facilities on ATCO Electric's proposed transmission line. However, the AUC noted that Lakeland REA stated that it was indifferent to the routing in this particular area and, in general, the AUC did not consider that the issues raised by Lakeland REA are so substantial that the two parties should not be able to come to an agreement to arrange for the understringing of the facilities. If parties are not able to reach an agreement, the Surface Rights Board could decide appropriate compensation to either relocate or understring the distribution line.

Concerning concerns raised regarding the removal of shelterbelt trees, the AUC noted a different route that would avoid the trees would result in a cost to ratepayers of $1 million. However, the AUC noted that if the transmission line was to be relocated to the north side of the road allowance, this would avoid the impacts to the shelterbelt. While it approved the route requiring the removal of the shelterbelt trees, it directed ATCO to determine whether a route on the north side of the road in that vicinity would have lower impacts than the approved route on the south side of the road.

***ATCO Electric Ltd. - Z Factor Compliance Filing to Decision 21609-D01-2019*, AUC Decision 25071-D01-2020**

Rates - Compliance Filing

In this decision, the AUC determined ATCO Electric Ltd.'s ("ATCO Electric's") compliance with AUC directions issued in Decision 21609-D01-2019. The AUC found that ATCO Electric complied with AUC directions and approved ATCO Electric's revised Z factor amount of $10.3 million related to 2016, and $3.2 million related to 2017. Further, the AUC approved the $0.051 million Z factor adjustment to be included in ATCO Electric's 2021 annual performance-based regulation ("PBR") rate adjustment filing to be refunded to customers over the 12-month period effective January 1, 2021, to December 31, 2021.

<u>Background</u>

On October 2, 2019, the AUC issued Decision 21609-D01-2019, regarding ATCO Electric's Z factor adjustment for the 2016 Regional Municipality of Wood Buffalo (RMWB) wildfire. The decision included seven directions, including a direction, Direction 7, requiring ATCO Electric to file a compliance filing on or before November 13, 2019.

<u>Directions 1 and 7</u>

Direction 1 required ATCO Electric to make certain adjustments to the applied-for amounts and provide specific information in the compliance filing to this decision, and Direction 7 required a compliance filing on or before November 13, 2019.

The AUC found that ATCO Electric complied with directions 1 and 7.

<u>Direction 2: Criterion 2 - Materiality Threshold</u>

The AUC's Direction 2 addressed the materiality threshold requirement of Criterion 24 for ATCO Electric's Z factor for 2017:

> The magnitude of the adjustments for 2017 as directed in Section 6 are more significant relative to the 2017 materiality threshold of $2.370 million. The Commission cannot therefore determine in this decision whether ATCO Electric's Z factor for 2017 is material. The Commission therefore directs ATCO Electric to reassess whether its Z factor for 2017 satisfies the materiality threshold requirement of Criterion 2 in its compliance filing to this decision.

The AUC reviewed ATCO Electric's revised 2017 Z factor revenue requirement calculation and was satisfied that ATCO Electric's applied-for 2017 Z factor adjustment of $3.158 million for costs incurred in 2017 exceeds the approved 2017 materiality threshold of $2.370 million. The AUC found that ATCO Electric complied with the AUC's Direction 2.

<u>Direction 3: Information Technology Costs</u>

Direction 3 required ATCO Electric to adjust the information technology ("IT") costs paid to Wipro to reflect the AUC's findings in Decision 20514-D02-2019:

> Consistent with the findings in Decision 20514-D02-2019, including that the IT services sourcing strategy was not prudent, the Commission finds that the IT costs paid to Wipro as applied for in this application were not prudently incurred. The Commission does not accept ATCO Electric's explanation above and as such, directs ATCO Electric to adjust the $0.061 million paid to Wipro to reflect the Commission's disallowance and glide path reductions as directed in Section 6 of Decision 20514-D02-2019 and to clearly show all calculations in the compliance filing to this decision.

The AUC directed ATCO Electric to recalculate the 2016 Z factor amount to reflect the adjustment made to the IT costs.

The AUC was satisfied that the adjustment to the $0.061 million paid to Wipro reflects the AUC's disallowance and glide path reductions as directed in Decision 20514-D02-2019. The AUC was also satisfied that ATCO Electric correctly reflected the reduction in its revised 2016 Z factor revenue requirement calculation. Accordingly, the AUC found that ATCO Electric complied with Direction 3.

<u>Direction 4</u>

The AUC concluded that for regulatory purposes, the RMWB wildfire gave rise to an extraordinary retirement of the destroyed assets and determined that:

> … As a result of these findings, the principles established by Stores Block and the related Court of Appeal decisions dictate that the remaining net book value of the destroyed assets associated with the RMWB wildfire must be for the account of the ATCO Electric shareholders. ATCO Electric is directed, in the compliance filing to this decision, to provide all accounting entries reflecting the retirement of the assets destroyed by the RMWB wildfire.

In response to this direction, ATCO Electric provided the accounting entries reflecting the retirement of the assets destroyed by the RMWB wildfire as follows:

> DR [Debit] Loss $3.177 million
>
> CR [Credit] Accumulated Depreciation $3.177 million

The AUC reviewed the accounting entries cited above supplied by ATCO Electric and was satisfied that the entries are consistent with the assets destroyed by the RMWB wildfire and reflect an extraordinary retirement of the destroyed assets.

The AUC was satisfied by ATCO Electric's explanation that the treatment of the destroyed assets as an extraordinary retirement will have minor impacts on the accumulated depreciation reserve and not affect the depreciation rate calculation as the cost of the destroyed assets has been removed from its plant balance. It accepted ATCO Electric's proposal to reflect the effect on the amortization of reserve differences in ATCO Electric's next depreciation study. The AUC found that ATCO Electric complied with Direction 4.

<u>Direction 5: Continued Use of the Assets After 2017</u>

The AUC considered that a verification of the continued use of the assets was warranted, given the uncertainty of whether all of the repaired and replaced assets continue to be used or required to be used after 2017. The AUC directed ATCO Electric to include further information about whether these assets would continue to be used after 2017.

The AUC reviewed the information provided by ATCO Electric, including the map showing active customers as at September 30, 2019, and the locations of the repaired and replaced assets as a result of the RMWB wildfire, and accepted that all of the assets that the AUC found were used or required to be used in 2016 and 2017 continue to be used or are required to be used after 2017. The AUC found that ATCO Electric complied with Direction 5.

<u>Direction 6</u>

The AUC directed ATCO Electric, in its compliance filing, to:

> … remove any costs associated with the Boundary Lake area and Fox Creek wildfires, recalculate the revenue requirement for 2016 and 2017, identify and remove the manager and supervisory labour costs from the O&M expenditures, adjust the insurance proceeds amount, adjust the IT service costs to reflect the directions in Decision 20514-D02-2019, recalculate the lost revenue for 2017 by excluding inactive sites after May 2, 2017, and recalculate the total Z factor amount for 2016 and 2017 to reflect these adjustments.

Boundary Lake Area and Fox Creek Wildfires Costs

The AUC was satisfied that the removal of costs associated with the Boundary Lake area and Fox Creek wildfires was done correctly. As a result, the AUC found that ATCO Electric has complied with this portion of Direction 6, and approved the reduction of $0.133 million to 2017 net rate base. ATCO Electric was directed to reflect the adjustment in its 2021 annual PBR rate adjustment filing.

Lost Revenue for 2017

The AUC reviewed the schedule provided by ATCO Electric showing how it excluded lost revenue from sites inactive on May 2, 2017, and was satisfied that the adjustment to the lost revenue was done correctly. The AUC was also satisfied that ATCO Electric correctly reflected the reduction in its revised 2017 total Z factor amount. Accordingly, the AUC found that ATCO Electric complied with this portion of Direction 6, and approved lost revenue costs of $0.814 million for 2017 as filed.

Manager and Supervisory Labour Costs and Insurance Proceeds Amount

The AUC verified that ATCO Electric removed the manager and supervisory labour costs of $0.147 million from the operations and maintenance ("O&M") expenditures and adjusted the insurance proceeds amount to the correct amount of $0.085 million. The AUC also reviewed the revised revenue requirement for 2016 and 2017. The AUC was satisfied that ATCO Electric correctly reflected the reductions in its revised 2016 and 2017 Z factor revenue requirement calculation, and as such, complied with this portion of Direction 6.

Based on the foregoing, combined with its determinations regarding ATCO Electric's compliance with the AUC's directions related to the Boundary Lake area and Fox Creek wildfires, the IT costs paid to Wipro and lost revenue for 2017, the AUC was satisfied that the revised total Z factor amount for 2016 and 2017 reflected all adjustments required as per Direction 6.

<u>Revised Z Factor Amount for 2016 and 2017</u>

The AUC determined that ATCO Electric complied with the AUC's directions from Decision 21609-D01-2019 and reflected the directed modifications in its revised Z factor calculation. The AUC, therefore, approved the revised Z factor amount of $10.3 million related to 2016, and $3.2 million for 2017.

The AUC noted that in Decision 23895-D01-2018, the AUC approved a 90 percent Z factor placeholder to be included in ATCO Electric's 2019 PBR rates, subject to true-up in subsequent PBR annual filings to reflect the approved amount. As such, the AUC approved the $0.051 million Z factor adjustment to be included in ATCO Electric's 2021 annual PBR filing to be refunded to customers over the 12-month period effective January 1, 2021, to December 31, 2021.

***ATCO Gas, a Division of ATCO Gas and Pipelines Ltd. - 2020 Transmission Service Charge (Rider T)*, AUC Decision 25283-D02-2020**

Rates - Transmission - Rider T

In this decision, the AUC approved the 2020 transmission service charge rider ("Rider T") rates for ATCO Gas, a division of ATCO Gas and Pipelines Ltd., effective March 1, 2020, on a final basis. The approved Rider T rates are as follows:

- low-use customers: $0.762 per gigajoule (GJ)
- mid-use customers: $0.696 per GJ
- high-use customers: $0.210 per day of GJ demand

<u>Background</u>

ATCO Gas flows through the rates charged by the transmission service provider, NOVA Gas Transmission Ltd. ("NGTL"), to customers. Rider T is the service charge used to collect forecast transmission costs and to refund or collect any differences between the prior year's forecast and actuals. ATCO Gas forecasts its transmission expense based on NGTL's rates and charges applied to the contract demand quantity ("CDQ"). Any difference between what ATCO Gas collects through Rider T based on its forecast and what it ultimately pays to NGTL based on actuals is recorded in a deferral account and refunded to, or recovered from, customers as part of a subsequent Rider T.

On April 24, 2019, NGTL received approval from the CER, formerly the National Energy Board, for its final 2019 rates, tolls and charges for the Alberta natural gas transmission system. Effective May 1, 2019, the NGTL interim FT-D3 rate decreased to $6.58 per GJ/month from $6.80 per GJ/month. The NGTL abandonment surcharge remained at $0.29 per

GJ/month through June 30, 2019, then decreased to $0.21 per GJ/month. Effective January 1, 2020, the NGTL interim FT-D3 rate increased to $7.1410 per GJ/month from $6.58 per GJ/month. The NGTL abandonment surcharge simultaneously decreased to $0.20 per GJ/month from $0.21 per GJ/month.

On January 17, 2020, ATCO Gas filed the application requesting approval for new Rider T rates to be effective on March 1, 2020. ATCO Gas requested approval for new Rider T rates to account for changes in the NGTL interim FT-D3 rate and abandonment surcharge, as detailed above.

Discussion of Issues

In Decision 2014-062, the AUC approved the implementation of a province-wide Rider T rate to replace the previous practice of maintaining separate Rider T rates for ATCO Gas's north and south service territories. Cross-subsidization issues between ATCO Gas's north and south service territories were considered in Decision 2014-06214 and have been addressed by the AUC in subsequent Rider T decisions.

ATCO Gas noted that the subsidy between typical residential customers in the north and south that results from applying a province-wide rate does not exceed $4.16 annually. ATCO Gas further explained that, under separate rates for north and south, a typical residential (low-use) customer in the north using 80 GJ between March and December would see a $1.04 increase in their annual bill, while a typical residential (low-use) customer in the south would see a $1.12 decrease in their annual bill.

ATCO Gas stated that the differences identified between the province-wide amounts and the separate north and south amounts result from two factors: billing determinants and CDQ. ATCO Gas explained that these factors are unique to each service area, and ATCO Gas is not able to change the billing determinants or contract requirements to minimize the differences in rates.

AUC Findings

The AUC found that for the purposes of this decision, this level of cross-subsidization is not significant enough to justify having separate rates for north and south, consistent with the AUC's acceptance of similar minimal cross-subsidization in prior decisions approving ATCO Gas's Rider T.

The AUC directed ATCO Gas to continue to track its Rider T cross-subsidization between north and south customers and to continue to provide, in its next Rider T application, the information on cross-subsidization.

Rider T Methodology and Rate Design

The AUC noted that there has been no change in the methodology that ATCO Gas uses to determine Rider T in the current application. The AUC found that the use of coincident peak demand ("CPD") to allocate transmission costs is a long-standing AUC-approved practice. While the Consumers' Coalition of Alberta ("CCA") had raised concerns about ATCO's methodology, in its evidence, the CCA had not provided an alternate methodology or provided any evidence that the current methodology is inadequate. The AUC was satisfied with the methodology that ATCO Gas used in the current proceeding, which is consistent with previous Rider T decisions concerning the cost allocation between rate groups and the use of CPD to allocate transmission costs.

Inclusion in Rider T of Legal Costs Related to the CER NGTL Rate Design and Services Application Proceeding

In its application, ATCO Gas included $399,576 of legal fees incurred as a result of its participation before the CER during the NGTL rate design and services application proceeding. ATCO Gas explained that its participation was required as part of the prudent management of its transmission expenses, which is consistent with its responsibility to arrange for economic delivery of adequate upstream transmission capacity in accordance with the *Roles, Relationships and Responsibilities Regulation*. NGTL proposed to significantly increase the FT-D3 rate and, as a result, ATCO Gas participated with the intention to reduce the proposed increase and ensure the transmission expense is just and reasonable.

AUC Findings

The AUC ruled previously that ATCO Gas's responsibilities under the *Roles, Relationships and Responsibilities Regulation* can include participation in proceedings regarding NGTL rates, and the AUC was not persuaded by the CCA in this case to revisit that conclusion.

The AUC was satisfied that ATCO Gas's intervention in this specific CER proceeding was due to NGTL's proposal to increase the FT-D3 rate and, as a result, ATCO Gas participated with the intention to reduce the proposed increase and to ensure that the transmission expense is just and reasonable.

The AUC was not convinced, however, that the expense associated with ATCO Gas's intervention should be recovered through Rider T. Specifically, the AUC was not persuaded that these costs should be recovered outside the revenue provided to ATCO Gas pursuant to the terms of its 2018-2022 PBR plan. In approving the 2018-2022 PBR plan, the AUC was clear that its approach was expected to expand PBR incentives to the vast majority of overall costs. Pursuant to the terms of its 2018-2022 PBR plan, ATCO Gas is provided with revenue that it spends as it determines is best to manage its obligations to provide safe and reliable service.

ATCO Gas argued that since 2016 was used to determine its O&M funding for its second-generation PBR rates, and there were no active NGTL proceedings in 2016, its PBR rates do not include legal costs for such participation. The AUC did not consider it relevant whether or not this particular expense was incurred in ATCO Gas's lowest cost O&M year. In approving the lowest cost O&M year as the basis of the going-in rates for the 2018-2022 PBR term, the AUC understood that some costs would not be captured in the lowest cost year. The AUC recognized that under the terms of its 2018-2022 PBR plan, certain costs may be incurred by ATCO Gas that were not contemplated in the lowest O&M year, while other costs that were contemplated may not be incurred. As a result, the AUC found that the legal fees of participation in the NGTL proceeding fall under the I-X mechanism.

Concerning whether the legal charges could be recovered through a Y factor under PBR, the AUC was not convinced that these charges, on a stand-alone basis, would satisfy the criteria for a Y factor.

Considering the above, the AUC denied recovery through Rider T of ATCO Gas's legal fees related to its participation before the CER as part of the NGTL rate design and services application proceeding. The AUC directed ATCO Gas to reflect the removal of the $399,576 of legal fees in its next Rider T application.

Rider T Rates and Bill Impacts

ATCO Gas explained that assuming an implementation date of March 1, 2020, the total annual charges for a residential (low-use) customer in the south service territory that utilizes 115 GJ annually would decrease to $696 from $712, and a similar residential customer in the north service territory would see a decrease to $736 from $752. ATCO Gas stated that the applied-for 2020 Rider T rate changes are reasonable and would not result in undue rate shock compared to existing distribution rates.

AUC Findings

The AUC found that the estimated rate impact of the March 1, 2020, Rider T is reasonable for all rate classes. The implementation of the 2020 Rider T results in rate decreases for all three rate groups, for both ATCO Gas North and ATCO Gas South.

For the reasons set out above, the Rider T rates were approved as applied for on a final basis, effective March 1, 2020.

***ATCO Gas and Pipelines Ltd. Franchise Agreement with the Village of Czar,* AUC Decision 25499-D01-2020**

Natural Gas - Franchise Agreement

In this decision, the AUC considered an application from ATCO Gas and Pipelines Ltd. ("ATCO") requesting approval of a natural gas franchise agreement (the "Franchise Agreement") with the Village of Czar ("Czar"). The AUC approved the proposed Franchise Agreement as filed.

Proposed Franchise Agreement and Franchise Rate Rider Schedule

Under the proposed Franchise Agreement, Czar would grant ATCO the exclusive right within the municipal service area to provide natural gas distribution service. The proposed Franchise Agreement would have a term of ten years. ATCO proposed a franchise fee of 11.84 percent, which was a continuation of the franchise fee from the previous franchise agreement between Czar and ATCO. The proposed franchise fee was less than the 35 percent franchise fee cap previously approved by the AUC.

The franchise fee was to be a payment in lieu of municipal property taxes pursuant to section 360 of the *Municipal Government Act* ("*MGA*"). The proposed Franchise Agreement included changes to the standard natural gas franchise agreement template, approved by the AUC in Decision 20069-D01-2015 to reflect this.

AUC Findings

Section 45 of the *MGA* deals with franchise agreements and provides that a municipal council may grant a right to a person to provide utility service in the municipality. Section 45(3) of the *MGA* provides that before such an agreement is made, it must be approved by the AUC. Similarly, section 49(1) of the *Gas Utilities Act* provides that no franchise granted to any owner of a gas utility by any municipality within Alberta is valid until approved by the AUC.

The AUC noted that, in considering whether to approve the Franchise Agreement, the AUC must determine whether the proposed agreement is necessary and proper for the public convenience, and properly conserves the public interests, as set out in section 49(2) of the *Gas Utilities Act* ("*GUA*").

The AUC stated that, in considering the franchise fee, its role is not to substitute its view on an appropriate franchise fee for that of the municipality, but to determine whether or not the level of the fee would result in an unreasonable burden on customers' utility bills. The AUC noted that, in this case, the proposed franchise fee of 11.84 percent was below the 35 percent fee cap previously approved by the AUC. Also, the franchise fee percentage was a continuation of the franchise fee from the previously approved franchise agreement between these parties. As a result, the AUC found the proposed franchise fee to be reasonable.

The AUC also noted the term of the proposed agreement was within the 20-year maximum specified by the *MGA*. As such, the term of the Franchise Agreement was acceptable to the AUC.

The AUC considered the proposed changes to the standard gas Franchise Agreement template. The AUC noted that Czar had been paid franchise fees in lieu of taxes in previous franchise agreements. The AUC also noted Czar had this option pursuant to section 360 of the *MGA*.

The AUC considered that the right granted to ATCO by Czar set forth in the proposed Franchise Agreement was necessary and proper for the public convenience and properly conserved the public interests. Accordingly, pursuant to section 45 of the *MGA* and section 49 of the *GUA*, the AUC approved the proposed Franchise Agreement as filed.

In accordance with section 36 of the *GUA*, the AUC also approved ATCO's Rate Rider A amount of 11.84 percent for customers in Czar, commencing on the date the proposed Franchise Agreement becomes effective.

***Canadian Natural Resources Limited -Primrose East Power Plant and Industrial System Designation Amendment Project*, AUC Decision 25184-D02-2020**

Facilities - Industrial System Designation

In this decision, the AUC considered applications from Canadian Natural Resources Limited ("CNRL") to construct and operate a 32-megawatt power ("MW") plant designated as the Primrose East Power Plant, and to amend the existing Primrose Industrial System Designation to include the Primrose East Power Plant. The AUC approved the applications.

Introduction and Background

In 2007, CNRL was granted an industrial system designation ("ISD") for its operation at the Primrose industrial complex. In this proceeding, CNRL requested approval to construct and operate a 32 MW power plant, and that the existing Primrose ISD be amended to include the 32-MW power plant.

CNRL stated that the proposed Primrose East Power Plant would consist of a natural gas power plant with one gas turbine generator unit and provision for the future installation of an associated heat recovery steam generator ("HRSG") unit. CNRL stated that its Primrose oil production facility is currently subject to provincially legislated oil production curtailment, and as such, does not currently have an increased demand for steam. It plans to convert the power plant to a cogeneration unit in the third quarter of 2023, subject to management approval, when more steam is required by the Primrose facility; and that because the electrical and steam demand growth is not in sync, it makes economic sense to install the power plant in advance of the HRSG.

Discussion

CNRL submitted an economic assessment of the project and demonstrated the project's economic benefit when compared to the purchase of power from the Alberta Interconnected Electric System ("AIES"). The economic assessment showed that at net present value, the project would result in $130 million in savings when compared to the option of purchasing power from the AIES. The assessment also demonstrated that there were savings from the project, compared to the option of purchasing power from the AIES, even when the export revenue and transmission charges were not considered.

CNRL hired an independent engineering consultant to investigate the transmission capacity of the Primrose ISD interconnecting circuit and the capability of the surrounding Cold Lake electrical system near the Primrose 859S Substation. The results of the investigation showed that a transmission facility upgrade would be required to serve the incremental load growth if the proposed project was not built. The capital cost of this upgrade was initially estimated to be between $10 and $15 million.

CNRL stated that although the Primrose ISD is a net importer of electricity, it has an existing Supply Transmission Service contract with the Alberta Electric System Operator for 85 MW. CNRL has sized the project, including the future HRSG addition, to meet the current and future load and steam requirements of the Primrose industrial complex. The industrial system would continue to exchange electricity with the AIES after the project is built. However, CNRL expects to use all of the power generated by the project within the Primrose industrial complex by 2026.

CNRL estimated the investment to install the proposed power plant to be $34.5 million, and the total investment for the installation of the proposed power plant, the future installation of the HRSG, and other process elements to be $105 million.

<u>AUC Findings</u>

The AUC outlined the statutory scheme, including the criteria for determining whether a project should be designated as an industrial system under section 4 of the *Hydro and Electric Energy Act* ("*HEEA"*).

The AUC was satisfied that the technical, siting, emissions, environmental and noise information provided meets the AUC's application requirements under Rule 007. It also found that the participant involvement program met the requirements of Rule 007.

The noise impact assessment predicted that the cumulative sound levels for the proposed power plant comply with the daytime and nighttime permissible sound levels, and the AUC was satisfied that the project complies with Rule 012.

The AUC considered that the economic assessment of the amended industrial system continues to support the development of an internal, economical supply of generation to meet the requirements of CNRL's integrated industrial processes. In addition, the amended ISD would support the principles of efficient and economic exchange with the AIES, while not facilitating an independent system or uneconomic bypass of the AIES.

The AUC was satisfied that, with the addition of the proposed power plant, the Primrose ISD will continue to meet all of the ISD criteria set out in subsection 4(3) of *HEEA* except for the common ownership requirement found in subsection 4(3)(c).

Subsections 4(4) and 4(5) set out further criteria for the AUC to consider when a project does not meet those set out in subsection 4(3). Subsection 4(4) states:

> (4) Where the Commission is not satisfied that subsection (3)(c) or (d) has been met, the Commission may make a designation under subsection (1) if the Commission is satisfied that all of the separately owned components and all of the industrial operations are components of an integrated industrial process.

In this instance, some of the components of the integrated system are owned by a joint venture that is 50 percent owned by CNRL and 50 percent owned by Heartland Generation Limited, and all the 25-kilovolt distribution facilities are owned and managed by ATCO Electric Ltd. Notwithstanding this, the AUC was satisfied that all of the separately owned components and all of the industrial operations are components of an integrated industrial process. Consequently, it found that the project substantially meets the requirements of subsection 4(4) of *HEEA.*

The AUC noted that subsection 4(5) gives it the discretion to approve an ISD application if subsections 4(3) and 4(4) have been substantially met and there is a significant and sustained increase in efficiency in a process of the industrial operation or in the production and consumption of electric energy by the industrial operation as a result of the integration of the electric system with the industrial operations the electric system forms part of and serves. The AUC found that subsections 4(3) and 4(4) were substantially met. Having considered the economic analysis provided by CNRL, it was also satisfied that the addition of generation capacity at this time will result in a significant and sustained increase in efficiency for the industrial operations on site.

The AUC approved the applications to construct and operate the 32-megawatt Primrose East Power Plant and to amend the existing Primrose Industrial System Designation to include the Primrose East Power Plant.

***City of Lethbridge - 2018-2020 Transmission Facility Owner - General Tariff* Application, AUC Decision 24847-D01-2020**

Rates - GTA

This decision set out the determinations of the AUC regarding a general tariff application (application or “GTA”) filed by the City of Lethbridge’s electric utility (“Lethbridge”) transmission facility owner (“TFO”) requesting approval of its revenue requirement for the 2018-2020 test period.

The AUC denied Lethbridge’s requested revenue requirement for the years 2018-2020 with respect to proposed 2020 escalation rates for “other” and “contractor” categories; a proposal to apply a direct assigned deferral account surplus to a hearing cost reserve account deficit; and certain depreciation expense related calculations. The AUC directed Lethbridge to respond to all directions set out in this decision by way of a compliance filing.

Introduction and Background

On August 28, 2019, Lethbridge filed an application with the AUC requesting approval of its 2018-2020 TFO GTA. The Consumers’ Coalition of Alberta (“CCA”) participated in the application.

Compliance With Outstanding Directions from Decision 21213-D01-2016

The AUC found that Lethbridge complied with Direction 1, which required a breakdown of labour and contractor costs for Account 563, to enable the AUC to track variances in such costs arising from the purchase of a bucket truck.

The AUC also found that subject to inflation assumptions, Lethbridge complied with Direction 2, which directed that Lethbridge address salaries and wages for employees, and other compensation issues.

Direction 10 required that Lethbridge reflect all incurred costs of removal into its accumulated depreciation account, rather than capitalizing costs of removal into its capital asset accounts. The AUC found that Lethbridge complied with this direction.

Direction 11 stated the following:

> 103. Lethbridge is also directed to include in its next application, a detailed explanation of its accounting practices for retirement, gross salvage and cost of removal. Lethbridge is further directed to include an explanation of its accounting practice for the disposition of utility assets, including the treatment of gains or losses, in a manner that will address the concerns raised by the Commission in paragraph 100 [parts (a) to (e)] above.

Concerning its accounting practices for gross salvage and cost of removal, Lethbridge explained in its response to Direction 11 that the City’s asset management system calculates depreciation on an individual asset basis, as opposed to the group depreciation method used by some other AUC regulated utilities.

To address the issue of never having a large enough balance of accumulated depreciation attributable to pre-collected net salvage, Lethbridge proposed to pool the pre-collection of all net salvage provisions for all asset accounts into an “asset retirement obligation” account. This single pooled account would then be charged (or drawn down against) with all subsequent salvage costs (costs of removal) as they are incurred. The AUC addressed issues with Direction 11 later in its decision.

Direction 12 from Decision 21213-D01-2016 required that Lethbridge address issues with its depreciation study accounts and provide additional information on depreciation parameters. The AUC found that Direction 12, in its entirety, remains outstanding until Lethbridge’s next depreciation study.

Forecasting Methodology and Key Assumptions

Operation and Maintenance Expenses

The AUC approved the 2018-2020 Operation and maintenance ("O&M") expenditures, subject to any further determinations made elsewhere in the decision that affected O&M expenses.

Inflation Factors

In its application, Lethbridge used actual 2018 expenses and then reverted to trends for 2019-2020.

The AUC considered that the escalation factor increases for unions of 1.75 percent were reasonable and consistent with the escalation rates of other municipalities and utilities. Further, the AUC considered that an escalation rate of 1.75 percent for administration employees for 2020, consistent with the Canadian Union of Public Employees, also appeared to be reasonable.

Given the lack of evidence filed by Lethbridge concerning the economic climate in the Lethbridge area, contactor quotes, or other supporting evidence, the AUC was not persuaded that Lethbridge's contractor escalator and "other" escalator should be higher than the 1.75 percent approved for unions and administration. Lethbridge was directed to incorporate a contractor and "other" escalation of 1.75 percent for the 2020 test year in its compliance filing to this decision.

Municipal Corporate Expenses

In the application, Lethbridge identified that it receives services from other municipal departments, and those transactions are considered to be analogous to "affiliate" transactions. Specifically, Lethbridge stated that these affiliate expenses are costs that are charged to the electric utility department from other municipal departments. The prices for these services are based on allocations that are subject to a public and transparent municipal budget approval process.

As the total municipal corporate expenses represented roughly 4.6 percent of Lethbridge's total gross revenue requirement, and in an effort to reduce regulatory burden, the AUC noted that it was willing to approve the O&M affiliate charges amounts for each of the 2018, 2019, and 2020 test years, respectively.

However, the AUC also agreed with the CCA that Lethbridge should better trace and track municipal corporate expenses to its transmission function, as well as have a better understanding of how allocation factors are determined or approved by City Council. The AUC directed Lethbridge to provide a general discussion of this process, and provide support for any changes to its allocation methodology and associated factors, at the time of its next GTA.

Depreciation Expense

The AUC observed several technical issues with Lethbridge's current depreciation practices that require resolution.

Lethbridge Deviations from Approved Depreciation Parameters and Associated Rates

The AUC noted that Lethbridge's statement that it was using depreciation rates that are not consistent with the "composite rate recommended by the depreciation study" or that Lethbridge was "at times [deviating] from the depreciation study parameters to avoid over-forecasting accumulated depreciation" was an issue in this proceeding.

For forecasting purposes, the AUC noted that there is no reason for Lethbridge to deviate, under any circumstance, from the use of approved depreciation parameters or rates.

The AUC directed that in all future GTAs, Lethbridge is to use AUC-approved depreciation parameters and associated rates to determine forecast depreciation expense.

Allocation of General Plant Accounts

The method by which Lethbridge allocates general plant assets to the transmission function was of particular concern to the AUC.

The AUC observed that Lethbridge's current practice is to re-allocate in the first test year the total City (distribution and transmission) amount of actual general plant assets and the total City amount of actual accumulated depreciation related to those assets based on revised test year allocation factors.

The AUC considered that for forecasting purposes, current additions to (transmission) general plant assets should be informed by the revised test year allocation factors. The current allocated portion, combined with prior year actual (transmission) general plant closing balances, is what is subject to transmission depreciation rates for the purposes of determining depreciation expense for Lethbridge's (transmission) general plant assets.

Lethbridge Practices Related to the Retirement of Utility Assets and the Proposed "Asset Retirement Obligation" Account

The AUC noted that there are two considerations with respect to the retirement of an asset from utility service: the retirement of the original historical cost (service life) and the subsequent recording of any net salvage incurred (net salvage) in the retirement of the assets.

In this proceeding, it was established that Lethbridge's accounting practice in transacting an asset retirement is to remove the original historical cost from the asset account, and the actual depreciation expense attributed to the asset from the corresponding accumulated depreciation account. The remaining net book value is recorded as a loss.

Where gross salvage amounts received are in excess of salvaging costs, Lethbridge records a gain in its accounting records.

The AUC observed that Lethbridge's asset retirement transactions, as described above, are contrary to group depreciation practices for both the retirement of the asset and any subsequent recording of net salvage.

With respect to service life, group depreciation practice is to remove the original historical cost of the retired asset from both the asset account and the corresponding accumulated depreciation account – thereby leaving any remaining net book value to be recovered from ratepayers under the assumption of an ordinary retirement event.

With respect to net salvage, notwithstanding Lethbridge's proposal to implement a single pooled "asset retirement obligation" account, the practice of recording a gain or a loss under the assumption of an ordinary retirement event is likewise contrary to group depreciation practices. Group depreciation practice is to record both salvage costs and gross salvage amounts received against the pre-collected net salvage amount in the accumulated depreciation account – there should be no gain or loss realized by Lethbridge for an ordinary retirement event.

The AUC directed Lethbridge to implement group depreciation practices for its capital and depreciation related accounting transactions and to determine forecast depreciation expense in all future GTAs.

The AUC noted that the issues noted in this section require resolution prior to the AUC approving Lethbridge's proposed "asset retirement obligation" account. For this reason, Lethbridge's proposed "asset retirement obligation" account was denied.

Next Steps

Having regard to issues in this proceeding, following Lethbridge's compliance filing to this decision, the AUC will establish a framework for the purpose of advancing Lethbridge's understanding of its regulatory reporting requirements. The AUC will also examine whether there may be simplified reporting requirements or methodologies to better accommodate Lethbridge's unique circumstances as a TFO. Lethbridge was also directed to arrange for a technical workshop with intervening parties and AUC staff, within three-to-six months before the anticipated filing of its next GTA.

<u>Capital Structure, Return on Equity and Cost of Debt</u>

The AUC was satisfied that for 2018-2020, Lethbridge had used the deemed capital structure of 37 percent equity and 63 percent debt, and a return on equity of 8.5 percent, consistent with the AUC's direction in Decision 22570-D01-2018.

Further, the AUC was satisfied that Lethbridge followed the same approach approved by the AUC in Decision 3599-D01-2015 by using the rates recorded by the Alberta Capital Finance Authority of 3.66 percent, 3.48 percent and 3.36 percent for its annual 2018-2020 forecast cost of debt.

<u>Reconciliation and Maintenance of Deferral and Reserve Accounts</u>

Lethbridge was directed to refund a direct assigned deferral account surplus amount of $95,000 related to its 2018 tariff and to recover the forecast hearing cost reserve deficit in equal amounts in 2018, 2019, and 2020. Lethbridge was directed to show the impact of this direction on its tariff in a compliance filing.

Transmission Tariff

Lethbridge was directed to incorporate the findings and directions in this decision in a compliance filing and to reflect the impact of doing so in a revised monthly tariff, including any required true-up.

***The Consumers' Coalition of Alberta -Decision on Preliminary Question, Application for Review of Decision 24475-D01-2019 - ATCO Electric Ltd. Hanna Region Transmission Development Deferral Account Costs* Award, AUC Decision 25245-D01-2020**

Costs Awards - Review and Variance

In this decision, the AUC considered an application (the "Review Application") filed by the Consumers' Coalition of Alberta ("CCA") requesting a review and variance of specific findings in AUC Decision 24475-D01-2019 (the "Costs Decision"). The Costs Decision addressed an application from the CCA for approval of its costs for participation in the ATCO Electric Hanna Regional Transmission Development ("HRTD") Deferral Account application (Proceeding 22393). The CCA's review application requested a reconsideration of the AUC's determination to reduce the CCA's consultant participation costs claim by 50 percent.

The AUC decided to allow the Review Application in part and varied the direction in the Costs Decision to reduce the CCA's consultant participation costs by 50 percent to a cost reduction of 25 percent.

In this decision, the AUC member(s) who authored the Costs Decision are referred to as the "Hearing Panel" and the AUC member(s) who considered the review application are referred to as the "Review Panel." The AUC members who authored Decision 22393-D02-2019 are referred to as the "HRTD AUC panel".

Background

On June 6, 2019, the AUC issued Decision 22393-D02-20194. On April 5, 2019, the CCA submitted its costs claim application for approval and payment of its costs of participation in Proceeding 22393 and the AUC assigned Proceeding 24475 to the Costs Proceeding.

The Hearing Panel issued the Costs Decision on November 25, 2019. The total costs claimed by the CCA were $773,002.50, and the Hearing Panel approved cost recovery of $407,321.54. The approved costs represented a 50 percent reduction of the costs claimed by the CCA's consultant, Bema Enterprises Ltd. ("Bema"), and a 15 percent reduction to the costs claimed by the CCA's legal representative, Wachowich & Company. The costs claimed by the CCA's consultant, Bema, were the subject of the review request.

The Hearing Panel's findings pertaining to Bema's cost claim were summarized as follows:

- Delay requests and the resultant costs to re-acquaint themselves with the record
- Limited assistance to the AUC in certain parts of the evidence filed
- Potential duplication of work performed by CCA

AUC's Review Process

The AUC noted that its authority to review its own decisions is discretionary and is found in Section 10 of the *Alberta Utilities Commission Act*. The review process has two stages. In the first stage, a review panel must decide whether there are grounds to review the original decision, referred to as the "preliminary question." If the review panel decides that there are grounds to review the decision, the AUC moves to the second stage of the review process where the AUC holds a hearing or other proceeding to decide whether to confirm, vary, or rescind the original decision.

In this decision, given the nature of the error(s) alleged, the Review Panel decided both the preliminary question and the variance question.

Grounds for Review and Review Panel Findings

The CCA alleged that the Hearing Panel made an error of fact, law, or jurisdiction. The six grounds in support of its review application, and the Hearing Panel's findings were as follows:

Grounds 1 and 2: Delays in Proceeding 22393 and Responsibility for Costs for Reacquainting With the Proceeding Record

The Review Panel noted that the Hearing Panel did not attribute all of the delays in the proceeding solely to the CCA. Rather, it stated that some of the delay was attributable to CCA requests that were, in part, driven by CCA resourcing issues. The Review Panel found that the Hearing Panel's factual determinations on these issues were supported by the record. These grounds of review were denied.

Ground 3: Quality of the Evidence

The Hearing Panel did not make a finding dismissing parts of the Bema evidence in its entirety, as suggested by the CCA in its review application. Rather, the Hearing Panel made a factual determination that because portions of Bema's evidence contained errors or were incomplete, that, when considering the assistance to the AUC of this evidence, all of the costs incurred by Bema in preparing its evidence were not warranted. The Review Panel noted that it is not its task to second guess the weight assigned by the Hearing Panel to various pieces of evidence. This ground of review was denied.

Ground 4: Duplication of Efforts and Review Work Performed

The CCA argued that only time spent reviewing and revising work was claimed, and therefore there was no duplication of costs. The Review Panel noted that it was clear on the face of the Costs Decision that the Hearing Panel was aware that work included revisions, not just reviewing. The Hearing Panel recognized that there was overlap, it was simply not persuaded that all of the time spent reviewing and revising the work of the multiple consultants was kept to a minimum or that it was reasonable to ask ratepayers to pay for those costs in the absence of sufficient detail. This ground of review was denied.

Ground 5: Procedural Fairness

The CCA argued that it was procedurally unfair of the Hearing Panel to seek clarification from ATCO Electric on its costs, but not to provide a similar opportunity to the CCA to provide further explanation of its costs application.

The Review Panel noted that the CCA filed a 201-page costs application, replete with each of the invoices it relied on to support its costs claim. The CCA was also provided with the opportunity to file whatever submissions it wished to make in support of the costs it was requesting. As such, the Hearing Panel had before it all of the underlying supporting documentation that was available to make its decision. This ground of review was denied.

Ground 6: Mathematical Error

The CCA provided analysis to demonstrate that even accepting each of the findings above would not substantiate a 50 percent cost disallowance.

The Review Panel noted that it was clear from the Costs Decision, that each of the findings: (1) refamiliarizing work due to delays; (2) quality of some portions of the evidence; and (3) duplication of work all supported a disallowance of the total costs claimed by Bema.

However, based on the analysis provided, and review of the costs record, the Review Panel found that, on its face, the combination of each of these findings would not substantiate 50 percent of the total Bema costs disallowed.

Decision

In answering the preliminary question, the Review Panel found that the CCA did not meet the requirements for a review of the findings in the Costs Decision based on grounds 1 through 5.

However, with regard to argument ground 6, regarding whether the totality of the reasons presented supports a 50 percent disallowance of Bema's costs, the Review Panel found that the CCA demonstrated that an error existed on a balance of probabilities and that there is a reasonable possibility that this error could lead the AUC to materially vary or rescind the Decision.

The AUC considered that no additional information or submissions from parties was required and proceeded to the second stage of deciding whether to confirm, vary or rescind the 50 percent disallowance in the Costs Decision.

The Review Panel considered that a 25 percent reduction of hours claimed would reflect the findings. Accordingly, the Costs Decision was varied by deleting the words "50 percent reduction" and replacing them with the words "25 percent reduction."

Drumheller Solar Corporation - Drumheller Solar and Battery Storage **Project, AUC Decision 25234-D01-2020**

Facilities - Solar - Battery Storage

In this decision the AUC considered applications from Drumheller Solar Corporation ("DSC") to construct and operate a solar power plant and a battery energy storage system designated as the Drumheller Solar and Battery Storage Project and to connect the project to ATCO Electric Ltd.'s ("ATCO's") 25-kilovolt electric distribution system. The AUC approved the applications.

Introduction and Application Details

On December 24, 2019, DSC applied with the AUC to seek an approval to construct and operate a 13.5-megawatt ("MW") solar power plant and a battery energy storage system ("BESS") with a nameplate capacity and storage capacity of eight MW and eight megawatt-hours, respectively. The project would be located southeast of Drumheller within the municipal boundary of the town of Drumheller. DSC also applied to connect the project to the Alberta Interconnected Electric System ("AIES") via ATCO's 25-kilovolt distribution system. The applications were filed under sections 11 and 18 of the *Hydro and Electric Energy Act*.

DSC confirmed that the BESS would be charged exclusively from the solar power plant and would not be charged by the AIES. DSC also confirmed that the combined project export to the AIES would not exceed 13.5 MW.

DSC outlined the safety and control systems for the project. DSC explained that in the very unlikely event of a thermal runaway, the automatic fire suppression system would respond to the combustion event.

A solar glare report was conducted, which estimated that the project would produce solar glare at two of the seven dwellings used as receptors as well as along Highway 10.

Effects on the Environment

An environmental evaluation concluded that the potential adverse effects of the project could be avoided, reduced, or controlled with implementation of the standard and project-specific mitigation measures outlined in the environmental evaluation.

Findings

The AUC reviewed the applications and determined that the technical, siting, emissions, environmental and noise aspects of the power plant were met. DSC's participant involvement program was conducted, and there were no outstanding public or industry objections or concerns.

The AUC noted that neither the legislative scheme nor the AUC's rules specifically address battery storage. DSC filed the application as a solar power plant with a BESS. The AUC, therefore, considered the implications of the battery storage project in that context. In accordance with Section 17 of the *Alberta Utilities Commission Act,* the AUC must assess whether the Drumheller Solar and Battery Storage Project is in the public interest, having regard to the associated social, economic, and other effects of the project, and its effect on the environment.

The AUC considered that the public interest would be largely met if an application complies with existing regulatory standards, and the project's public benefits outweigh its negative impacts.

The AUC determined that the application was in the public interest and that all requirements for the project would be satisfied. The AUC approved the application to construct and operate the project subject to the following conditions:

a. DSC will conduct post-construction carcass surveys and wildlife monitoring for a minimum of one year in accordance with the standards outlined in the *Wildlife Directive for Alberta Solar Energy Projects (2017)*; and

b. DSC shall submit a post-construction monitoring survey report to Alberta Environment and Parks ("AEP") and the AUC within 13 months of the project becoming operational. Based on the findings of the report, additional post-construction carcass surveys and wildlife monitoring may be required to determine the effectiveness of any additional mitigation measures required by AEP.

***ENMAX Power Corporation - Highway 8 Transmission Line 138-7.82L Relocation* Project, AUC Decision 24831-D01-2020**

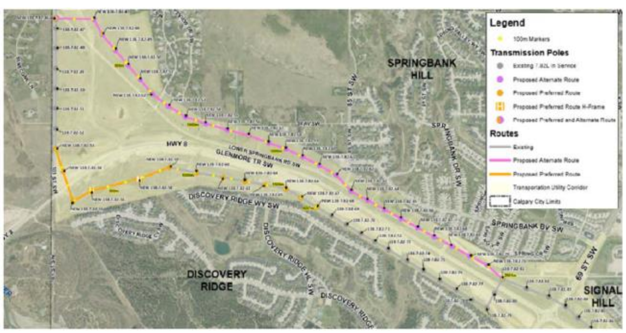
Facilities - Transmission Line

In this decision, the AUC considered an application from ENMAX Power Corporation ("ENMAX") to alter and operate Transmission Line 138-7.82L near Highway 8 in the southwest quadrant of the City of Calgary. The AUC found that approval of ENMAX's preferred route was in the public interest, having regard to the social and economic effects of the project and its effect on the environment, in accordance with Section 17 of the *Alberta Utilities Commission Act* ("*AUCA"*).

Introduction and Background

ENMAX is the owner of Transmission Line 138-7.82L, which is located in the Calgary transportation and utility corridor ("TUC") and its current location conflicts with the construction and planned infrastructure of the West Calgary Ring Road ("WCRR"). Alberta Transportation directed ENMAX to relocate certain portions of the line to accommodate the WCRR construction.

ENMAX applied to the AUC for approval under sections 14, 15, and 21 of the *Hydro and Electric Energy Act* ("*HEEA*") to alter, remove and relocate a portion of Transmission Line 138-7.82L near Highway 8 in the City of Calgary. ENMAX applied for approval of one of its two proposed routes, the south-central route (in yellow) and the north route (in pink), as shown in the figure below, as the proposed preferred and alternate routes, respectively.



ENMAX designated the south-central route as its preferred route based on its assessment of impacts on stakeholders and the environment. For the south-central route, ENMAX requested approval to remove 16 existing wood poles, to construct approximately 1.8 kilometres of overhead single-circuit 138-kV line, and to install 13 new steel structures.

ENMAX designated the north route as its alternate route. For the north route, ENMAX requested approval to remove 34 structures of the existing line, to construct approximately 2.9 kilometres of overhead single-circuit 138-kV line, and to install 25 new single-circuit self-supporting steel monopoles.

The proposed structures on both routes would range in height from 18 to 33 metres, resulting in an increase in height from the existing wood poles, which are between 19 and 26 metres tall.

ENMAX estimated the cost of the south-central route at $3.91 million, and the estimated cost of the north route at $6.24 million.

Interventions and Standing

The AUC received statements of intent to participate from local residents and landowners, and from the Slopes Community Association ("SCA"), the Springbank Hill Community Association ("SBHCA"), the Discovery Ridge Community Association ("DRCA") and the Pinebrook Estates Homeowners Association (that later joined with an individual to become the Mortimer / Pinebrook Group). The SCA/SBHCA retained Trevor Cline to provide evidence on their behalf.

The issues raised in the statements of intent to participate mainly focused on the routing of the relocated line and residential impacts. The AUC granted standing to the above-captioned groups and several individuals.

Routing

ENMAX retained Maskwa Environmental Consulting Ltd. ("Maskwa") to conduct the routing assessment for the project and identify potential routes with the lowest impact. Maskwa determined the south-central route to be the preferred route based on its lower overall impacts when compared to the north route. The north route was identified as the alternate route.

ENMAX concluded that both the preferred and alternate routes were viable and comparable, avoid or minimize potential negative impacts, and are located within the TUC.

Temporary Options to Retain the Existing Line

Mr. Cline prepared a report that concluded that ENMAX could retain the existing line route by either: (a) constructing a temporary line for use during WCRR construction, or (b) constructing a temporary alternate connection to supply customers during WCRR construction.

The AUC rejected these alternatives, noting that the temporary supply alternative would require the AESO to submit a needs identification document application. Both alternatives would require portions of the permanent line route, including structures, to be located in the exclusion zone within which Alberta Transportation specifically stated transmission structures are not permitted.

All-dielectric Self-supporting Proposal

Mr. Cline proposed a modification to the south-central route to address stakeholder concerns about visual impacts related to the larger and taller poles. He stated that the height of the poles is governed by the all-dielectric self-supporting ("ADSS") fibre-optic cable because it is the lowest cable on the structures. He suggested that removing the ADSS cable from the poles and burying it underground would result in the lowest transmission conductor governing pole height, which would allow for an approximately 1.5-metre reduction in the height of the structures.

The AUC rejected this suggestion, accepting ENMAX's evidence that burying the ADSS cable would increase the risk to customer reliability, given the additional transition points that would be required in the system.

Need for Future Substation 45

The Mortimer Pinebrook Group retained Pablo Argenal of Nican International Consulting Ltd. to prepare a report that included a historical review of publicly available transmission and distribution planning information relating to Transmission Line 138-7.82L. Mr. Argenal concluded that since approximately 1993, ENMAX has been aware of the need for a future substation, referred to as Substation 45, to be located in proximity to the proposed project.

Mr. Argenal submitted that Substation 45 would be required to provide sufficient backup through the distribution system if there is an N-1 or N-2 outage at an existing substation. He submitted that the north route aligns well with the previously identified Substation 45 location and that this is a relevant factor in favour of approval of the north route.

The AUC considered Mr. Argenal's assertion that there will be a need for a future substation in the TUC to serve increasing load levels in the west Calgary area and that this need should favour the north route for the relocation of Transmission Line 138-7.82L. However, the AUC was satisfied that ENMAX has a plan to reliably serve area load for the next ten years, including by undertaking the recent upgrades to Substation No. 7. It was also satisfied that ENMAX has reasonably considered other options for serving load growth beyond the 10-year period that do not require a new substation within the TUC.

Historical Approval of the Line Route

The DRCA referred to policy documents that indicated that the ring road would require the positioning of the relocated line on the north side of Highway 8. The AUC rejected the assertion that the decision had already been made by authorities that Transmission Line 138-7.82L must be routed north of Highway 8 when its relocation was required for WCRR construction.

Residential Impacts

The AUC accepted ENMAX's conclusion that both routes have comparable but not identical residential impacts, and in particular, that no residence would be within 50 metres of a newly built portion of the line on either route.

The AUC accepted that the south-central route uses more of the existing transmission line alignment than the north route and considered this to be one of the two factors that favours approval of the south-central route. The other factor is the lower cost to construct the south-central route.

Participant Involvement Program

The AUC found that ENMAX satisfied the notice and consultation requirements of Rule 007. The AUC was satisfied that residents along both routes were sufficiently engaged by ENMAX in project development and accepted that ENMAX incorporated stakeholder feedback wherever feasible.

Environment

The AUC found that both routes would have minimal potential negative impacts on the environment. Both routes would be located entirely within the TUC, which is land designated by the Government of Alberta for major linear facilities such as roads and transmission lines.

Project Cost

The AUC accepted ENMAX's cost estimates and observed that the estimate for the south-central route is approximately 38 percent less than the estimate for the north route. The AUC further understood that the shorter length of new build or rebuild on the south-central route is the most significant factor in the difference in cost estimates between the two routes, and was satisfied that relocating the line to the south-central route would be less costly than relocating it to the north route.

Decision

The AUC found that relocating Transmission Line 138-7.82L to the south-central route, including salvaging portions of the existing line, is in the public interest pursuant to Section 17 of the *AUCA.*

Pursuant to sections 14, 15, 19, and 21 of *HEEA*, the AUC approved the application. The AUC noted that the facilities in this application would all be located within the TUC. Under the *Calgary Restricted Development Area Regulations,* the AUC cannot issue a permit and licence for the construction and operation of facilities within the TUC without the written consent of the Minister of Infrastructure. The permit and licence for the project will, therefore, be issued once the written consent of the Minister of Infrastructure has been filed with the AUC.

***Heartland Generation Ltd. - Battle River Power Plant* Amendment, AUC Decision 25493-D01-2020**

Coal Plant Conversion

In this decision, the AUC considered an application from Heartland Generation Ltd. ("Heartland") to amend the approval for the Battle River Power Plant to allow Unit No. 5 to operate as a dual fuel coal and natural gas unit until December 31, 2022. The AUC approved the application.

Background

Alberta Power (2000) Ltd. ("Alberta Power"), an affiliate of Heartland Generation Ltd., is the owner of the Battle River Power Plant. The power plant consists of Battle River Unit No. 4 and Unit No. 5.

In Decision 23558-D01-2018, the AUC granted Alberta Power approval to alter the power plant by converting Battle River Power Plant Unit No. 5 from coal-fuelled to natural gas-fuelled. The power plant is currently operating under Approval 25222-D02-2020.

Heartland, on behalf of Alberta Power, filed an application with the AUC for approval to amend the power plant approval to allow Unit No. 5 to operate as a dual fuel coal and natural gas unit until December 31, 2022. Heartland indicated that it intends to convert Unit No. 5 from being a coal-fuelled unit to a dual fuel coal and natural gas unit prior to obtaining a reliable natural gas supply. Heartland stated Unit No. 5 cannot be classified as a natural gas-fuelled unit until a reliable natural gas supply is obtained.

Findings

The AUC accepted that converting Unit No. 5 to operate as a dual fuel coal and natural gas unit prior to 2022 will lower emissions and provide resiliency when natural gas supply is disrupted when compared to operating as a coal-fuelled unit. The AUC also accepted that the proposed amendment does not require additional consultation, given the potential reduction of impacts.

Approval 25222-D02-2020 was updated to state:

> 6. Unit No. 5 may operate as a dual fuel coal and natural gas unit until December 31, 2022.

***TransAlta Corporation - Keephills Power Plant* Repowering, AUC Decision 25240-D01-2020**

Coal Plant Conversion

In this decision, the AUC considered whether to approve an application from TransAlta Corporation ("TransAlta") for the alteration of a power plant, designated as the Keephills Power Plant, by constructing and operating a new combined-cycle power plant to repower Keephills Unit 1 (the "Project"). The AUC approved the application.

Background

TransAlta applied to the AUC for approval under sections 11 and 19 of the *Hydro and Electric Energy Act* to alter Keephills by installing a new combined-cycle power plant to repower Keephills Unit 1.

Keephills units 1 and 2 are in the process of being converted from coal-fuelled to natural gas-fuelled. They have been approved to operate as coal-fuelled until alterations have been completed.

The AUC noted that TransAlta is seeking approval to alter Keephills by constructing and operating one combustion turbine generator and one heat recovery steam turbine generator to repower Keephills Unit 1. The newly installed turbine would be integrated with the existing facility to produce electricity and steam. The produced steam would drive the existing Keephills Unit 1 steam turbine generators.

Separately, TransAlta registered a similar application, Application 25239-A001, to alter the Sundance Power Plant by installing a new combined-cycle power plant to repower Sundance Unit 5. The Sundance Power Plant is also located in the Wabamun Lake area, approximately five kilometres from Keephills.

Findings

The AUC determined that the technical, siting, environmental and noise aspects of the application were met. The AUC was satisfied that TransAlta conducted its participant involvement program in accordance with Rule 007.

The AUC found that the Project complies with Rule 012. It was satisfied with TransAlta's use of conservative assumptions in its modelling, and expects that if non-compliances are discovered, TransAlta would mitigate them appropriately.

The AUC noted that TransAlta submitted the application with generic equipment assessed, which it indicated would be representative of the equipment that would eventually be installed. The AUC requires confirmation that the final equipment selection would not materially change the impacts of the Project from what was detailed in the application. Therefore, any approval granted by the AUC is conditional upon the following:

> a. Once TransAlta has made its final selection of equipment for the Keephills Unit 1 project, it must file a letter with the Commission that identifies the make and model of the generating units. In this letter, TransAlta must also confirm that the project will not increase the land, noise, or environmental impacts beyond those reflected in the materials submitted by TransAlta in its application and approved by the Commission. The letter is to be filed no later than 30 days before construction of the project would commence.

Based on the foregoing, the AUC found that the approval of the Project is in the public interest.

CANADA ENERGY REGULATOR

Application for a Compensation Hearing Under Section 327 of the Canadian Energy Regulator Act Between Peace River Greenhouses Ltd. And Westcoast Energy Inc., Carrying on Business As Spectra Energy Transmission

Arbitration - CER Jurisdiction

On October 10, 2019, Peace River Greenhouses Ltd. ("PRG") filed an application ("Application") for a compensation hearing under section 327 of the *Canadian Energy Regulator Act* ("*CER Act*"). The Application sought compensation from Westcoast Energy Inc., carrying on business as Spectra Energy Transmission ("Westcoast") regarding two of its pipelines across PRG's property.

In August 2009, PRG served the Minister of Natural Resources ("Minister") a notice to arbitrate under subsection 90(1) of the former *National Energy Board Act* ("*NEB Act*"). The Minister appointed a three-member arbitration committee ("Arbitration Committee") to consider the matter.

PRG argued that the arbitration had been concluded since 2012. In the alternative, PRG sought to terminate the arbitration.

Westcoast requested that the CER dismiss the Application because the arbitration remains assigned to the Arbitration Committee and is extant. Pursuant to section 41 of the transitional provisions associated with the *CER Act*, Westcoast argued that the CER lacks jurisdiction to consider the Application.

The CER dismissed the Application for the reasons below.

The *CER Act* came into force on 28 August 2019. Section 41 of the transitional provisions associated with the *CER Act* provides that any request for which a notice to arbitrate was served on the Minister under subsection 90(1) of the *NEB Act* is continued in accordance with those subsections.

Under section 96 of the *NEB Act,* the Minister may terminate the appointment of the Arbitration Committee if the Minister is satisfied that the Committee has no arbitration work to carry out. There was no evidence that the Minister terminated the appointment of the Arbitration Committee.

Westcoast stated that in 2012, the Arbitration Committee held that PRG repeatedly failed to comply with the Arbitration Committee's directions and orders regarding document and expert report disclosure. As a result, the Arbitration Committee stayed the arbitration until PRG completed its document disclosure obligations. In the fall of 2014, the Arbitration Committee responded to the parties after receiving correspondence from PRG. The Arbitration Committee noted that the arbitration remained assigned to the Arbitration Committee and that before the arbitration could resume, PRG must comply with the outstanding orders. PRG did not dispute this in its submissions.

The CER noted that the arbitration remains assigned to the Arbitration Committee. The arbitration provisions under the *NEB Act*, therefore, continue to apply, pursuant to section 41 of the transitional provisions associated with the *CER Act*. The CER found that it has no authority to terminate the appointment of the Arbitration Committee or to otherwise conclude its mandate. It determined that it is without jurisdiction to consider the Application. The Application was dismissed.

Maritimes & Northeast Pipeline Management Ltd. Abandonment Hearing MHW-001-2020 - Application to Abandon the Deep Panuke Custody Transfer Station

Abandonment

The CER considered Maritimes & Northeast Pipeline Management Ltd.'s ("M&NP")'s application to abandon the deep panuke custody transfer station filed with the National Energy Board ("NEB") on August 22, 2019 (the "Application").

The Application was filed before the coming into force of the *Canadian Energy Regulator Act* ("*CER Act*"). Pursuant to section 36 of the transitional provisions of the *CER Act*, the Application was considered by the CER in accordance with the *National Energy Board Act* ("*NEB Act*").

The Application described activities related to the abandonment of the Deep Panuke Custody Transfer Station ("Station"). The CER issued Order ZO-001-2020 ("Order"), the effect of which is to grant M&NP leave to abandon the Station.

Project Overview and the Process

M&NP's Application sought leave to abandon the Station ("Project"). M&NP indicated it would abandon the Project by removing all related surface equipment and below-ground infrastructure at the station site. The existing gravel pad at the station site will be left in place, and the area will be maintained as an access site for the M&NP mainline pipeline. The Project is located on approximately 0.2 ha of land, and M&NP abandonment activities would be confined to the Station footprint and existing M&NP right-of-way.

Under the *NEB Act*, the CER must hold a public hearing to consider an application for leave to abandon a pipeline. The CER issued Notice of Abandonment Hearing MHW-001-2020 for the Project ("Notice") on 7 January 2020, which set out how the CER would consider the Application.

Assessment of the Application

Engineering Matters

The CER found that the abandonment activities for the Station, as proposed by M&NP, are consistent with the legislative requirements related to the abandonment of piping, equipment, and related facilities at stations.

The CER reminded M&NP that it must conduct all abandonment activities in compliance with the *National Energy Board Onshore Pipeline Regulations* (*"OPR*") and Canadian Standards Association (CSA) Standard CSA Z662-19.

Technical Matters

In response to M&NP's statement that releases will be immediately reported to the Nova Scotia Environment Emergency Line or the Canadian Coast Guard, the CER stated that notifications of releases are required by various federal and provincial regulations. There is no notification-sharing agreement between the CER and the Nova Scotia Department of Environment or the Canadian Coast Guard. Therefore the CER was of the view that a report to those agencies will not satisfy the requirement to report to the CER.

The CER reminded M&NP of the requirement under the *CER Act* to report incidents to the CER in accordance to the NEB Event Reporting Guidelines.

Economic and Financial Matters

The CER accepted that Encana will be funding the full cost of the Project and, based on the submissions provided by M&NP, agreed that there will be no impact to M&NP's toll as a result of the Project. Further, the CER was of the view that M&NP's Abandonment Trust could be drawn upon in the case of unforeseen liabilities or other obligations created by or arising from the Project. In light of the foregoing, the CER was satisfied that the Project will have no impact on MN&P's tolls and that M&NP can finance the Project abandonment work.

The CER noted that improving the future accuracy of the CER's Abandonment Cost Estimates is an ongoing process that benefits from the accumulation of data. Therefore, the CER imposed a condition which requires M&NP to provide actual cost data broken down by abandonment activity.

Lands, Consultation and Socio-economic Matters

The CER found that the Project would have negligible environmental or socio-economic effects on Indigenous interests due to its small scale and localized nature on previously disturbed privately held industrial land, with no associated potential for traditional use activities to be affected.

The CER was satisfied that the socio-economic and lands impacts of the Project are not likely to be significant due to the small scale, short duration, and location of the Project within the original Station footprint with access by private road and the application of standard mitigation measures.

The CER noted the concerns raised by Maw-lukutijik Saqmaq regarding potential disturbance of heritage resources during the completion of physical abandonment activities. It noted that M&NP received the necessary heritage and archaeological resources clearance from the province prior to the original Station construction in 2010 and that no archaeological or heritage resources were found or disturbed at the site at that time.

The CER found M&NP's view, namely that no new on-the-ground archaeological testing would be carried out as a result of this Project as these measures had taken place already before the original construction of the Station and no heritage resources were found at that time, to be reasonable.

To ensure that mitigation measures to protect previously unidentified heritage resources are adequately implemented, the CER imposed a condition ("Condition 3") requiring M&NP to file its Environmental Protection Plan ("EPP") with the CER and to serve a copy on Maw-lukutijik Saqmaq. The EPP must include a contingency plan to be implemented if previously unidentified heritage resources are encountered, including measures implemented in accordance with the *Nova Scotia Heritage Property Act*.

The CER found the likelihood of any potential negative impacts of a socio-economic nature or related to the lands from the Project to be remote, and in any event that it would be limited in extent, short term, and reversible, and therefore not likely to be significant.

Environment Matters

The CER noted the concerns raised by Maw-lukutijik Saqmaq regarding leaving the Project site as graveled following the completion of the physical abandonment activities. However, the CER noted that M&NP owns the Project lands in fee simple within the boundaries of an industrial park and is planning to retain ownership of the land area for ongoing operational purposes and potential future uses.

Regarding the concerns raised by the Maw-lukutijik Saqmaq about the wetland located adjacent to the southwest corner of the Project site, the CER reviewed information in the Environmental Screening Final Report ("ESFR") submitted by M&NP in its application to the NEB to construct the Project in 2009, as well as the 2012 Post-Construction Monitoring Report filed with the NEB by Encana for the Deep Panuke Project in 2012. The ESFR indicated that the Project site is located within lands formerly owned by Encana and that water approvals were issued by Nova Scotia Environment to Encana for wetland alterations during construction of the Deep Panuke Project, including the Station site. As a condition of those approvals, Encana committed to restoring and compensating wetland loss to ensure no net loss of wetland function. Encana's Post-Construction Monitoring Report ("PCMR") confirmed that a small area of permanent alteration occurred in the wetland of concern to the Maw-lukutijik Saqmaq. In its PCMR, Encana did not identify any outstanding issues regarding wetlands but did confirm that a report would be prepared and submitted to Nova Scotia Environment and Environment Canada, summarizing the results of the wetland monitoring program.

Based on the information contained in the reports noted above, as well as the information provided by M&NP in its Application and related filings as part of this proceeding, the CER was of the view that if there are still any outstanding issues relating to this wetland, the responsibility for them lies with Encana and Nova Scotia Environment, and not M&NP. The CER was also satisfied that any historical residual effects of constructing the Project site on the wetland located adjacent to the southwest corner of the site were addressed by Encana as part of the Deep Panuke Project.

The CER again noted that, while M&NP indicated it had prepared an EPP for the Project, a copy of the EPP was not included in its Application. To ensure that the mitigation measures to protect the wetland and other environmental features on and adjacent to the Project site are adequately implemented, the CER again made note of Condition 3, which requires M&NP to file its EPP with the CER and to serve a copy on Maw-lukutijik Saqmaq.

Considering the nature and scope of the Project, M&NP's proposed mitigation measures, and with the implementation of Condition 3, the CER was of the view that any potential adverse environmental effects arising from the Project would not be significant, as they would be of limited geographic extent, short term, and reversible.

Decision

The CER granted M&NP leave to abandon the Project.

TransCanada PipeLines Limited Application for Approval of the Mainline 2021-2026 Settlement Letter Decision

Settlement - Tolls

The CER received an application from TransCanada PipeLines Limited ("TCPL") dated December 20, 2019, requesting approval of the Mainline 2021-2026 Settlement (the "Application"). The Settlement was for tolling and services matters for the 1 January 2021 to 31 December 2026 period (the "Settlement"). TCPL filed its Application for approval pursuant to the tolls and tariff and public interest provisions under Parts 1 and 3 of the *Canadian Energy Regulator Act* (*"CER Act"*) and the Revised Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs ("Settlement Guidelines").

As described in the Settlement, tolls for the 2021-2026 period would be determined on a cost of service basis, by segment, with an agreed-upon level of cost and revenue variance sharing between TCPL and shippers. Tolls would be fixed for the term, subject to a one-time Long Term Adjustment Account ("LTAA") adjustment in 2020, although tolls would be subject to rate riders should the Short Term Adjustment Accounts ("STAAs") exceed or be expected to exceed an agreed-upon threshold. While the Application addressed tolls for the 2021-2026 period, it also included proposals for service matters that would commence prior to 2021, including the implementation of the proposed new complaint-based Market Driven Service ("MDS") and changes to renewal provisions.

TCPL submitted that the Settlement represents a balance of interests resulting from compromises of the diverse interests and positions of parties. As such, TCPL presented the components of the Settlement to the CER for approval as a package without modification.

TCPL also submitted that discussions with members of the Tolls Task Force ("TTF") were initiated in late 2018 and confirmed that TCPL hosted formal meetings over 40 individual dates in various locations. A TTF vote was held on 16 December 2019, with the result being a unanimous decision, meaning that all parties who took a position voted in support of the Settlement.

Views of the CER

The CER found that the Settlement will result in tolls that are just and reasonable, and tolls and services that are not unjustly discriminatory. Having determined that the Settlement complies with the requirements of sections 230 and 235 of the *CER Act*, the CER approved the Application as filed.

In reaching this determination, the CER gave significant weight to the unanimous TTF support for the Settlement and the absence of submissions opposing or raising concerns about the Settlement. The CER reviewed all aspects of the Application and identified no material concerns extending beyond the immediate concerns of the negotiating parties. The CER also found that the Settlement met the requirements of the Settlement Guidelines.

Having reviewed the information filed on the record to support the Settlement, the CER found that the Settlement will provide shippers with a degree of certainty on tolls and service attributes over the next six years. In the CER's view, this is beneficial as it allows shippers to make more informed contracting and investment decisions. At the same time, measures have been developed to allow TCPL a reasonable opportunity to recover its costs, including the potential for rate riders to be charged.

Additionally, the Settlement provides TCPL with the ability to quickly meet market demands with market solutions through the new complaint-based MDS. As structured under the Settlement, the MDS will provide benefits to both shippers and TCPL. Through the Incentive Sharing Mechanism, TCPL and its shippers also agreed to share variances in costs and revenues during the Settlement's term. Both shippers and TCPL will benefit from initiatives to attract incremental revenues to the Mainline and to reduce costs. Overall, the CER found that the Settlement struck an appropriate balance between the respective interests of the negotiating parties, which was demonstrated by the unanimous support.

For these reasons, the CER approved the Application as filed.

Trans Mountain Pipeline ULC Application for Approval of Its 2019 Depreciation Study and Revised Depreciation Rates, Effective 1 January 2020 Letter Decision

Depreciation

On 1 October 2019, Trans Mountain Pipeline ULC ("Trans Mountain") submitted an application for approval of its 2019 Depreciation Study and revised depreciation rates, effective 1 January 2020 (the "Application"). The CER approved the Application and will require Trans Mountain to file a new depreciation study, along with specific evidence related to the treatment of ongoing future capital requirements, no later than 1 August 2021. Toll order TO-001-2020 gives effect to this decision, with the revised depreciation rates being approved effective 1 January 2020.

Trans Mountain's Application

The 2019 Depreciation Study included Trans Mountain's assets used to provide rate-regulated service ("Rate Regulated Assets") and its assets used to provide merchant service ("Merchant Assets"), all as of 31 December 2018. The depreciation rates were based on the straight-line method using an average life group procedure, applied on a remaining life basis.

The estimated survivor curves in the 2019 Depreciation Study were based on studies incorporating actual data through 2018 for most accounts. The estimated survivor curves were truncated to reflect an anticipated economic planning horizon ("EPH") of 31 December 2048 (corresponding to a 30-year EPH), which is nine years later than the 31 December 2039 EPH used in Trans Mountain's prior, 2010 depreciation study (which also corresponded to a 30-year EPH). Trans Mountain submitted that the EPH is meant to capture changes to anticipated service life that are not from normal depreciation; EPH reflects the influence of factors such as oil supply, market demand, and competition.

The 2019 Depreciation Study produced recommended composite depreciation rates applicable to the Rate Regulated Assets and Merchant Assets of 2.41% and 3.19%, respectively. The composite rate for Trans Mountain's Rate Regulated Assets was 3.12% in its 2010 depreciation study (that study did not include any Merchant Assets). Trans Mountain indicated that for most accounts, the depreciation rate decreased due to the renewal of the 30-year EPH from the 2010 depreciation study. Trans Mountain indicated that if approved, the depreciation rates in the 2019 Depreciation Study would cause the annual depreciation expense for the Rate Regulated Assets to decrease starting in 2020 (which, all else equal, would reduce tolls through an approximately $5.3 million reduction in the annual revenue requirement).

<u>Views of the CER</u>

The CER noted that the methodology used in Trans Mountain's 2019 Depreciation Study was consistent with that used in Trans Mountain's prior depreciation study and several other depreciation studies for CER-regulated pipelines. However, the CER noted that two interveners submitted comments on the EPH, and the CER also had concerns regarding future capital requirements.

EPH

The CER noted the view of the Canadian Association of Petroleum Producers ("CAPP") that the EPH was conservative and KM Canada North 40 Limited Partnership's ("KM Canada's") view that because of greater outbound pipeline connectivity, the merchant tanks at the Edmonton Terminal are expected to have a longer useful life. The CER also noted that KM Canada did not request any relief from the CER in this regard, nor request the ability to submit further evidence.

The CER accepted Trans Mountain's reply that no one factor (such as availability of market demand) is determinative of EPH, and given KM Canada's limited submission, the CER was not persuaded that the EPH applied to the merchant tanks at the Edmonton Terminal should be different from that applied to the Rate Regulated Assets. In terms of Trans Mountain's evidence in support of the EPH, the CER noted that it would often expect a more detailed assessment and rationale in support of the selected EPH. However, the CER accepted the EPH in this instance given that no current shippers chose to further pursue the EPH matter, and given that the CER found that Trans Mountain Expansion Project ("TMEP") being under construction provides a compelling rationale for why the EPH should not be materially shorter than 30 years.

Future Capital Spending

Concerning the exclusion of future capital costs from the 2019 Depreciation Study, the CER's interest stemmed from the pattern in recent years for Trans Mountain's Rate Regulated Assets, and the expectation that the pattern will continue (setting aside TMEP impacts), of capital requirements offsetting a large portion of the depreciation expense. The result has been, and is expected to continue to be, that the net value of the Rate Regulated Assets decreases at a very slow rate, while the applicable depreciation rates reflect a 30-year EPH.

Trans Mountain submitted that only under certain circumstances would the exclusion of future capital additions not indicate that the estimated depreciation rates are too low. The CER noted that one of the circumstances is that the EPH remains the same in future depreciation studies, which would mean that the end date of the economic horizon would be pushed to a later date. Trans Mountain indicated that when the EPH is expected to be shortened in the future, there is benefit to including forecast capital additions in depreciation rate calculations in order to avoid depreciation rate shock in future years. While the CER accepted that there is no certainty about what an EPH will be in future studies, the CER found that the logical expectation, or best guess, based on today's knowledge is that in the future, the economic life will tend to get shorter. That the future EPH could be longer or the same as the current EPH does not detract from this.

The CER found that forecast error, cited by Trans Mountain as the major reason for excluding future capital additions in depreciation studies, is not a compelling reason to exclude all forecast capital spending for the Rate Regulated Assets in the 2019 Depreciation Study. The CER observed that historical and forecast (non-TMEP) capital spending on the Rate Regulated Assets is quite stable (e.g. when looked at over the five year rolling intervals shown by Trans Mountain) and stays above approximately $24 million each year. Further, no evidence was presented to suggest that these amounts will materially decrease in the future, let alone fall to zero. The CER found that this suggests that there is substantial ongoing capital spending for the Rate Regulated Assets that is not discretionary (e.g. capital that is of a maintenance/repair nature). As a result, the CER was of the view that excluding all future capital spending for the Rate Regulated Assets could effectively introduce a larger forecast error than would a best efforts forecast of these future additions.

In light of the above, the CER was concerned that ongoing future capital requirements could, if not appropriately dealt with, contribute to future depreciation expense shock for shippers on the Rate Regulated Assets. The CER was of the view that this issue should be further explored after substantial additional evidence is provided by Trans Mountain, and after such evidence can be considered and responded to by parties affected by the resulting tolls. However, the CER noted that preparation and regulatory consideration of that evidence would take time. The CER also recognized that Trans Mountain's approach is common among depreciation studies, the issue is one that by its nature has a long time horizon, and shippers would benefit from the certainty of tolls not remaining interim for an extended period of time. Accordingly, the CER decided to accept the 2019 Depreciation Study's treatment of future capital additions at this time, while requiring Trans Mountain to return at a later date with additional submissions, as outlined below.

Based on the foregoing, the CER decided to approve the Application as filed.

Requirement for Future Filing by Trans Mountain

Given the CER's concern regarding future capital requirements, the CER issued a toll order directing Trans Mountain to file a new depreciation study by 1 August 2021, based on account balances as of 31 December 2020. As part of its filing, Trans Mountain is directed to submit a thorough theoretical and practical assessment of whether / how ongoing future capital requirements could / should be reflected in the new deprecation study.

The CER noted that Trans Mountain's submissions should examine the implications for and fairness in respect of different generations of toll payers. For example, the CER is interested in whether it is fair to depreciate much of today's invested capital in consistent amounts over 30 years, if the only way that capital can still be useful for 30 years is if substantial capital is invested in the intervening years (capital which will only be depreciated/paid for by shippers from the time it enters service through to the end of the EPH).

Trans Mountain Pipeline ULC Trans Mountain Expansion Project Detailed Route Hearings MH-002-2020 (Sugarloaf Ranches Ltd.) and MH-003-2020 (KGHM Ajax Mining Inc.)

Pipeline - Routing

Background

The Trans Mountain Expansion Project ("TMEP") includes twinning the existing 1,147-kilometre-long Trans Mountain Pipeline ("TMPL") system in Alberta and British Columbia ("BC") with approximately 981 kilometres of new buried pipeline; new and modified facilities, such as pump stations and additional tanker loading facilities at the Westridge Marine Terminal in Burnaby; and reactivating 193 kilometres of the existing pipeline between Edmonton and Burnaby. Trans Mountain Pipeline ULC ("Trans Mountain") requested approval of a 150-metre-wide corridor for the TMEP pipeline's general route.

The CER briefly outlined the procedural history of the TMEP, including the process for landowners and Indigenous peoples who filed statements of opposition ("SOOs") involving the proposed detailed route. (*Please see the summary* of *Trans Mountain Pipeline ULC Trans Mountain Expansion Project - Review of Decision MH-003-2018 Issued to 1054408 BC Ltd. in Detailed Route Hearing* (CER Decision MH-001-2020), also included *in the April 2020 Decisions issue for the complete procedural history.)*

Detailed Route Hearings MH-002-2020 and MH-003-2020

In 2017, KGHM Ajax Mining Inc. ("KGHM") and Sugarloaf Ranches Ltd. ("Sugarloaf") were each granted a detailed route hearing. A hearing process was held, including oral portions in May of 2018.

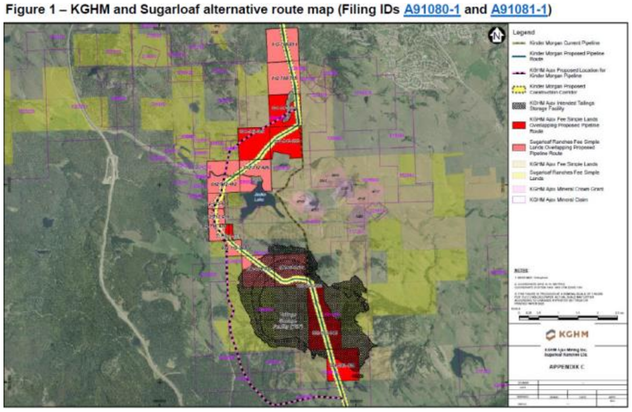
In 2019, KGHM/Sugarloaf filed SOOs seeking to resume their detailed route hearings. In their SOOs, KGHM/Sugarloaf did not describe a material change in circumstances since the 2017/18 detailed route approval process was held.

The CER decided that it would not permit the filing of additional evidence given that no material change in circumstances was established, but that it would hear oral final argument from the parties in Calgary on 3 February 2020, to allow the parties the opportunity to persuade the current decision-makers.

Introduction to the Proposed TMEP on the Lands

The CER set out the details regarding the lands ("Lands") subject to this detailed route hearing. It noted that Trans Mountain proposed to route approximately 11.7 kilometres of new pipeline across the Lands, as illustrated in Figure 1 below (in blue/yellow). The figure also illustrated KGHM/Sugarloaf's proposed alternate route (in pink).

Figure 1 – KGHM and Sugarloaf alternative route map (Filing IDs A91080-1 and A91081-1)



Trans Mountain's submissions

- The TMEP corridor deviates from the TMPL on the Lands to circumvent Jacko Lake.
- The proposed detailed route minimizes the length of the new easement before returning to the TMPL easement.
- The proposed detailed route is the best possible detailed route through the Lands since it minimizes cultural and environmental impacts by providing a buffer area between the TMEP and Jacko Lake.
- The final construction schedule will be determined by, among other things, regulatory approval, seasonal restrictions, and contractor availability.
- Trans Mountain proposes to employ conventional open-cut construction on the Lands and will work with KGHM/Sugarloaf to establish access plans to minimize disruption from construction activities.

KGHM/Sugarloaf's Submissions

- KGHM's proposed Ajax Mine Project includes an open-pit copper/gold mine that, if approved, is expected to process 65,000 tonnes of ore per day for export over a mine life of 23 years. The Ajax Mine Project includes a tailings storage facility ("TSF") designed to permanently store approximately 440 million tonnes of tailings generated during mine operations. The TSF would be comprised of four earth-rockfill dams or embankments to contain the tailings and water.
- The alternate route is a better route through the Lands than Trans Mountain's proposed detailed route because it avoids the future location of a TSF for the Ajax Mine Project, while also circumventing Jacko Lake.

Is Trans Mountain's Proposed Detailed Route for the TMEP Pipeline the Best Possible Detailed Route?

The CER's Decision on the Status of the Ajax Mine Project

The CER noted the status of the Ajax Mine Project is an important routing consideration because the proposed detailed route would traverse the location identified for the TSF, an important part of the Ajax Mine Project.

The CER recognized that the Ajax Mine Project is well defined; it was apparent that a significant amount of studies and effort had been invested to define and advance the proposed project. The CER recognized KGHM/Sugarloaf's submission that the Ajax Mine Project might obtain the necessary regulatory approvals and proceed at some time in the future, given the value of the resource proposed to be developed.

However, the CER was not convinced of when, or if, and under what conditions, the Ajax Mine Project could or would proceed. The CER noted that the BC Ministers of Environment and Climate Change

Strategy ("ECCS") and Energy, Mines and Petroleum ("EMP") declined to issue an Environmental Assessment ("EA") Certificate for the project. The federal government found that the project is likely to result in significant adverse environmental effects and referred it back to Fisheries and Oceans Canada and Natural Resources Canada to determine whether those effects can be justified in the circumstances, pursuant to section 37 of the *Canadian Environmental Assessment Act*, 2012.

The CER was not convinced of the certainty of the TSF's ultimate location. While the opinion of KGHM/Sugarloaf's witness was that the location of the TSF would not change, and that the location of the TSF was not an issue for the Stk'emlupsemc te Secwepemc of the Secwepemc Nation ("SSN") or the project's regulators, there was no evidence to support this claim. Further, KGHM/Sugarloaf provided no evidence of a material change in circumstances that would suggest that the decisions by BC and federal authorities are being reconsidered, or approved, in their current form, in the foreseeable future. For these reasons, the CER was of the view that the Ajax Mine Project is speculative at this time.

Did Trans Mountain Apply Its Routing Criteria Appropriately?

The CER outlined Trans Mountain's routing criteria, and acknowledged the NEB's recommendation regarding, and the Governor in Council's ("GIC") approval of that routing criteria.

When viewed as a whole, and given the speculative nature of the Ajax Mine Project, the CER decided that Trans Mountain appropriately applied the approved routing criteria in locating the proposed detailed route on the Lands.

Should the CER Consider an Alternate Route Outside the Approved Corridor?

The CER considered Trans Mountain's submissions that the TMEP corridor was approved by the Federal Cabinet following a Certificate Hearing, and that changing the corridor from the GIC approved corridor would require a variance application, resulting in a CER regulatory proceeding. Such a process would require new engagement with Indigenous peoples and affected landowners, and public notices. Following any process, the matter would also require GIC approval.

Notwithstanding those submissions, the CER agreed with KGHM/Sugarloaf that the CER could consider an alternate route outside of the approved corridor. The CER would not be in a position to approve a detailed route outside of the approved corridor. However, evidence of an alternate route outside of the approved corridor falls within the scope of the issue of the best possible detailed route of the pipeline, to the extent that it may assist the CER in determining whether the applied-for detailed route is the best possible detailed route. Therefore, the CER considered KGHM/Sugarloaf's proposed alternate route for the purpose of assessing Trans Mountain's proposed detailed route.

The CER agreed with KGHM/Sugarloaf's submission that, should the CER determine that Trans Mountain's proposed detailed route is not the best possible detailed route, then any delay or inconvenience associated with a variance application is a burden that Trans Mountain must bear.

Is the Proposed Detailed Route Superior to the Alternate Route?

Having found that the Ajax Mining Project is speculative, and that the location of any future TSF is uncertain, the CER decided that it is preferable for the TMEP to twin the TMPL to the extent possible, rather than to avoid the proposed TSF site.

The CER was of the view that KGHM/Sugarloaf's alternate route was designed essentially to avoid the TSF associated with the Ajax Mine Project. However, the CER also considered whether other features of the alternate route demonstrate that Trans Mountain's proposed detailed route is not the best possible detailed route across the Lands.

Having assessed the proposed and alternate routes, including balancing their respective advantages and disadvantages, the CER decided that Trans Mountain's proposed detailed route is superior to the alternate route. The proposed detailed route follows the approved routing criteria, including paralleling more of the existing TMPL than the alternate. In addition, the CER was swayed by the comparison provided in Trans Mountain's reply evidence showing that the proposed detailed route involves fewer road crossings and crosses fewer woodlots. The CER placed considerable weight on the fact that the proposed detailed route has potential impacts on fewer sites identified as important by Indigenous peoples and wildlife habitat areas for species at risk.

The CER noted that both parties appeared to agree that, if the Ajax Mine Project were to proceed in the future, the TMEP would need to be relocated. The CER accepted that this hypothetical scenario is a possibility, and saw value in attempting to avoid the impact associated with having to relocate the pipeline. However, the CER was of the view that such a scenario cannot be avoided with reasonable certainty at this time, given the speculative nature of the Ajax Mine Project. The CER agreed with Trans Mountain that it would not be prudent to route a pipeline to avoid a speculative mining project with the possibility that such a route, involving greenfield development with its associated environmental and socio-economic impacts, may turn out to be unnecessary if the Ajax Mine Project were to change or not proceed.

Further, the CER was of the view that, even if the speculative Ajax Mine Project were to occur in the future, the presence of the TMEP would not prevent it from proceeding, and it does not prevent the TSF from being located in the current proposed site. A commercial arrangement could be made, and the pipeline could be relocated, if necessary, consistent with the past relocation of the TMPL related to the Afton Mine. The CER noted that, if the Ajax Mine Project were to proceed and the TSF was to be located where it is presently proposed, the existing TMPL, which is currently situated at that location, would need to be relocated in any event.

The CER's Overall Decision on Whether the Proposed Detailed Route Is the Best Possible Detailed Route

Having considered the record, including Trans Mountain's commitments, the CER decided that Trans Mountain's proposed detailed route is the best possible detailed route across the Lands.

<u>Are Trans Mountain's Proposed Methods and Timing of Constructing the TMEP Pipeline the Most Appropriate?</u>

Having considered all of the evidence, including Trans Mountain's commitments, the CER decided that Trans Mountain's proposed methods and timing of constructing the TMEP pipeline across the Lands are the most appropriate.

<u>Conclusion</u>

Having decided that Trans Mountain's proposed detailed route is the best possible detailed route on the Lands, and that the proposed methods and timing of construction are the most appropriate, the CER approved the Plan Profile and Book of Reference ("PPBoR") for the Lands.

The CER noted that any future order approving the PPBoR for the Lands would include conditions requiring Trans Mountain to list and fulfill the commitments it made in the course of these detailed route hearings and to update its alignment sheets.

***Trans Mountain Pipeline ULC Trans Mountain Expansion Project - Review of Decision MH-003-2018 Issued to 1054408 BC Ltd. in Detailed Route Hearing*, CER Decision MH-001-2020**

Pipeline - Routing

<u>Background</u>

On 16 December 2013, Trans Mountain Pipeline ULC ("Trans Mountain") applied with the National Energy Board ("NEB") under section 52 of the *National Energy Board Act* ("*NEB Act*") for a certificate of public convenience and necessity ("Certificate") authorizing the construction and operation of the Trans Mountain Expansion Project ("TMEP").

The TMEP includes twinning the existing 1,147-kilometre-long Trans Mountain Pipeline ("TMPL") system in Alberta and British Columbia ("BC") with approximately 981 kilometres of new buried pipeline; new and modified facilities, such as pump stations and additional tanker loading facilities at the Westridge Marine Terminal in Burnaby; and reactivating 193 kilometres of the existing pipeline between Edmonton and Burnaby. Trans Mountain requested approval of a 150-metre-wide corridor for the TMEP pipeline's general route.

Upon receipt of the application, the NEB commenced a public hearing process ("Certificate Hearing"). Following the Certificate Hearing, on 19 May 2016, the NEB issued its Report recommending that the Governor in Council ("GIC") approve the TMEP and its general pipeline corridor. The TMEP was approved by Order in Council ("OIC") in November 2016. The NEB issued Certificate OC-064 and began work on various regulatory processes, including the 2017/18 detailed route approval process.

On 27 July 2018, the NEB released its decision in Detailed Route Hearing MH-003-2018 pertaining to 1054408 BC Ltd.'s lands ("2018 Decision").

On 30 August 2018, the Federal Court of Appeal ("FCA") issued its decision in *Tsleil-Waututh Nation v. Canada* (Attorney General) ("FCA Decision"), setting aside the OIC and remitting the matter back to the GIC for appropriate action. Following the FCA Decision, the NEB reconsidered the matter of TMEP-related marine shipping, and the Government of Canada reinitiated consultations with Indigenous peoples.

Following a second public hearing process, the NEB issued its Reconsideration Report in February 2019. Canada's Crown Consultation and Accommodation Report was issued in June 2019. The GIC approved the TMEP again in June 2019 via OIC, and the NEB subsequently issued Certificate OC-065.

On 19 July 2019, following a public comment process, the NEB set out how it would resume the TMEP detailed route approval process. The NEB directed Trans Mountain to file its Plan, Profile and Book of Reference ("PPBoR") for the entire TMEP route. Pursuant to section 34 of the *NEB Act*, Trans Mountain served landowners along the length of the TMEP with a notice that the detailed route approval process was underway, and placed notices in local publications. The notices indicated that landowners and Indigenous peoples with a continued or new objection to the proposed detailed route, or to the methods or timing of construction, were required to file a statement of opposition (SOO).

The NEB said that, in cases where a detailed route hearing decision had been issued, and a valid SOO was filed, a review of the prior decision would be conducted. To be considered valid, an SOO had to:

- be filed on time, made in good faith, not withdrawn, and not frivolous or vexatious;

  and

- identify a material change in circumstances related to the best possible detailed route of the pipeline, or the most appropriate methods or timing of constructing the pipeline.

On 28 August 2019, the *Canadian Energy Regulator Act* ("*CER Act*") came into force, repealing the *NEB Act*. As of that date, the Commission of the CER considered approval of the PPBoR under the *CER Act*.

<u>Review of the 2018 Decision</u>

In its 2018 decision, the NEB found Trans Mountain's proposed detailed route to be the best possible detailed route (the "2018 Decision"). It also found Trans Mountain's proposed methods of construction (including the amount and location of temporary workspaces) and its proposed timing of construction (June to September 2019) to be the most appropriate. On 5 September 2019, 1054408 BC Ltd. filed an SOO in which it raised objections to the methods and timing of construction.

In a procedural direction, the CER set out the scope of the review. The CER found that 1054408 BC Ltd. had identified a material change in circumstances that raised a doubt as to the correctness of the 2018 Decision concerning the timing of construction. Since no material change was raised concerning the methods of construction, the only issue to be decided in this review was whether the 2018 Decision, as it related to the timing of construction, should be confirmed, amended, or overturned.

The NEB's full finding concerning the timing of the TMEP's construction reads as follows (emphasis added):

> As discussed in evidence, Trans Mountain must obtain an authorization from [Fisheries and Oceans Canada (DFO)] for the Coquihalla River crossing, and there is a least-risk activity window of August 1-31 in any given year to conduct it. Preparation work will need to be done on 1054408 BC Ltd.'s lands in advance of the crossing, and clean-up activities following it. To avoid disrupting the lands a second time, the [NEB] is of the view that work to install the TMEP pipeline on 1054408 BC Ltd.'s property should be done at the same time as the river crossing. Accordingly, the Board finds that the most appropriate timeframe for pipeline construction on 1054408 BC Ltd.'s lands is between **June and September**.
>
> The necessary authorizations, including this detailed route approval, were not provided to Trans Mountain in time to conduct crossing- or pipeline-related work on 1054408 BC Ltd.'s lands in August 2018. While the August 2020 timeframe is possible from a regulatory perspective, the Board is of the view that, from a constructability perspective, pipeline construction on 1054408 BC Ltd.'s lands must precede construction of the residential development. The [NEB] agrees with Trans Mountain that the river crossing will not be feasible if the workspace becomes unavailable

> through development by 1054408 BC Ltd. The [NEB] also recognizes Trans Mountain's concerns around additional excavation and storage of material if fill has been added to the lands as part of requirements for 1054408 BC Ltd. to implement flood-proofing measures for the residential development.
>
> For these reasons, the [NEB] finds that **June to September 2019** is the most appropriate timing for the TMEP's construction on 1054408 BC Ltd.'s property.

Because of the delay due to the FCA Decision and subsequent approval steps, Trans Mountain was unable to construct from June to September 2019 and sought an amendment so that it could construct from June to September 2020. 105448 BC Ltd. argued that its planned residential development was being impeded by TMEP. It further argued that Trans Mountain's request for an amendment to extend the year of construction from 2019 to 2020 be denied.

<u>Decision of the CER</u>

Should the NEB's Decision That June to September Is the Most Appropriate Timing of Construction Be Confirmed, Amended, or Overturned?

The CER noted that it is an expert tribunal overseeing Trans Mountain's compliance with respect to TMEP-related river crossings. In this capacity, the CER is aware that the least-risk activity window to which Fisheries and Oceans Canada limits construction, in this case, has not changed.

The CER was of the view that conducting the river crossing during the least-risk activity window is important to protect fish and fish habitat, which is the very intent of such a window. The CER also continued to be of the view expressed in the 2018 Decision that pipeline construction on 1054408 BC Ltd.'s lands should be done at the same time as the river crossing (which involves preparatory and post-construction work on 1054408 BC Ltd.'s lands) in order to avoid disrupting the lands a second time. Accordingly, the CER confirmed the 2018 Decision that June to September is the most appropriate timing of construction.

Should the NEB's Decision That 2019 Is the Most Appropriate Timing of Construction Be Confirmed, Amended or Overturned?

The CER was of the view that the inclusion of the year in the 2018 Decision was based on the premise that pipeline construction should precede 1054408 BC Ltd.'s Phase 2 construction in the first June to September period that was available. At the time of the 2018 Decision, this meant the year 2019. There was no question that the TMEP's construction on 1054408 BC Ltd.'s lands could not have occurred in 2019, given the FCA and NEB decisions that followed the 2018 Decision. Further, as a matter of common sense, the CER cannot require the construction to take place in the past.

Trans Mountain requested that the year of construction be amended to 2020. The CER noted that Trans Mountain must obtain any necessary authorizations and approvals from all relevant regulators and government offices in order to begin its construction activities. The CER agreed with 1054408 BC Ltd.'s submission that the requirement to obtain these approvals may interfere with pipeline construction in 2020. As noted below, the lands at issue are also the subject of the S'ólh Téméxw Stewardship Alliance's ("STSA") ongoing opposition, such that any PPBoR approval related to 1054408 BC Ltd.'s lands cannot be issued immediately following the release of the CER's decision in this review.

Having considered the submissions of Trans Mountain and 1054408 BC Ltd., the CER continued to be of the view expressed in the 2018 Decision that pipeline construction must proceed first. The additional fill and loss of workspace resulting from development by 1054408 BC Ltd. would impair Trans Mountain's ability to complete construction of the TMEP.

For these reasons, the CER found Trans Mountain's request to revise the year of construction from 2019 to 2020 to be unnecessary. As a matter of practicality, the CER was not specifying a particular year for construction. The CER amended the 2018 Decision to read that the most appropriate timing for the TMEP's construction is **June to September**.

The Relevance of the Reason for a Lack of Approval of Phase 2 of 1054408 BC Ltd.'s Residential Development

The CER acknowledged 1054408 BC Ltd.'s desire to begin work on Phase 2 of its residential development as soon as possible. The CER also accepted 1054408 BC Ltd.'s evidence that the TMEP is impeding this work, including with respect to related approvals. However, the CER noted that these facts were not relevant to the CER's decision in this review. The GIC has approved the TMEP and the only issue currently before the CER related to the timing of construction. The CER agreed with Trans Mountain that any potential impacts on 1054408 BC Ltd. as a result of the TMEP's construction are appropriately matters of compensation outside the scope of the detailed route approval process.

Conditions and PPBoR Approval

The CER noted that, as of the date of this decision, 1054408 BC Ltd.'s lands are also subject to the broader SOO filed by the STSA, which is being examined in Detailed Route Hearing MH-027-2020. Until the CER makes all necessary detailed routing decisions pertaining to 1054408 BC Ltd.'s lands, it cannot issue any order approving the associated PPBoR.

As was noted in the 2018 Decision, any future order approving the PPBoR for 1054408 BC Ltd.'s lands will include a condition requiring Trans Mountain to fulfill the commitments it made in the course of Detailed Route Hearing MH-003-2018, including Trans Mountain's commitment to engage and work with 1054408 BC Ltd. regarding, among other things, the scheduling of construction activities.

Trans Mountain was also reminded that the relevant conditions of approval in Certificate OC-065 apply to the construction and operation of the TMEP pipeline on 1054408 BC Ltd.'s lands.