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, consistent with public interest requirements. RLC follows a team approach, including when working with our clients and industry experts. Visit our website to learn more about RLC.

IN THIS ISSUE:

SUPREME COURT OF CANADA

***Hydro-Québec v Matta*, 2020 SCC 37**

Transmission Lines - Right of Way Agreements - Servitudes

This decision involved a dispute regarding the applicability of servitude agreements entered into during the 1970s for the routing of a transmission line. The Supreme Court of Canada found that a servitude agreement, if entered into after the notice of expropriation, contains a more faithful definition of the scope and terms for exercise of the servitude of public utility than does the notice of expropriation. Servitude agreements are subject to the rules applicable to the interpretation of contracts. If their words are clear, effect must be given to the clearly expressed intention of the parties.

Facts

On March 13, 2015, the Régie de l'énergie du Québec authorized Hydro-Québec to construct a proposed electrical transmission line between the Chamouchouane transformer substation in Saguenay-Lac-St-Jean and the Bout-de-l'Île transformer substation in Montréal. Hydro-Québec realized that it would be easier to run the line through a corridor where it already had servitudes that had been established in the 1970s for a transmission line between the Jacques-Cartier substation near Québec and the Duvernay substation in Laval. Hydro-Québec's acquisition of those servitudes had involved two steps. Having been authorized by Order in Council ("OIC") to acquire them by expropriation, it had first served and published notices of expropriation, after which it had signed, with the then owners, notarial agreements that described the servitudes being established and provided for various indemnities that would be payable, including for any work that might be carried out on the servient land.

Hydro-Québec claimed that these servitudes authorized it to route up to three electrical transmission lines through the servient land. The current owners of the lots contested this claim; they submitted that the rights arising from the servitudes acquired when the Jacques-Cartier–Duvernay line was constructed were limited to that one line only.

Findings in the Lower Courts

The trial judge ruled in Hydro-Québec's favour. He found that the servitudes at issue had originally been acquired by expropriation, but that the subsequent agreements had clarified their purpose and scope. In his view, the agreements were clear: they authorized Hydro-Québec to erect three electrical transmission lines no matter what the origin or the destination of the electricity was.

The Court of Appeal allowed the owners' appeal. In the Court of Appeal's view, the servitudes at issue had been acquired by expropriation and should be characterized as servitudes established by operation of law. Their scope therefore had to be analyzed in light of the limits imposed by the Order in Council ("OIC") that authorized them. The Court of Appeal accordingly concluded that Hydro-Québec could not rely on the servitudes in its favour for the construction of the new line and that it had to proceed by way of new expropriations or agreements.

Supreme Court Ruling

The Supreme Court allowed the appeal. It found that the power line servitudes in favour of Hydro-Québec were not limited to the Jacques-Cartier–Duvernay Line; they authorized Hydro-Québec to route a second electrical transmission line through the owners' lots.

The Supreme Court noted that the trial judge was correct in characterizing the post-expropriation agreements as servitude agreements. The OIC, the notices of expropriation and the agreements are different types of documents, and it is important to distinguish them from one another. An OIC is an administrative act for the purpose of authorizing the exercise of the power to deprive a property owner of the enjoyment of the attributes of his or her right of ownership. Filing a notice of expropriation and the documents related to it is an administrative act that establishes and individualizes the servitude. As for the agreement, the Supreme Court noted that it relates to the ordinary exercise of civil rights and to the private law rules of contract. A servitude acquired by expropriation is, according to the classification set out in art. 1181 of the Civil Code of Québec, established by operation of law.

The Supreme Court held that neither the law nor public order bars the expropriating party and the expropriated party from clarifying or modifying such a servitude by mutual agreement: notices of expropriation thus do not preclude parties from negotiating conventional servitudes. It must be presumed that the servitude agreement, if entered into after the notice of expropriation, contains a more faithful definition of the scope and terms for exercise of the servitude of public utility than does the notice of expropriation. Servitude agreements are subject to the rules applicable to the interpretation of contracts. If their words are clear, effect must be given to the clearly expressed intention of the parties.

The Supreme Court further held that in the case at bar, the agreements at issue included a complete description of the servitudes, adding some details that did not appear in the notices of expropriation. In these circumstances, the agreements are the titles to which the owners of the servient land and the dominant land must refer in exercising their respective rights. Because the agreements are clear, the scope of the servitudes must be determined in light of their words. The agreements did not mention any restrictions regarding the origin or destination of the electricity. The servitudes were therefore not limited to the line between the Jacques-Cartier and Duvernay substations. The servitudes on the owners' lots authorized Hydro-Québec to construct the Chamouchouane–Bout-de-l'Île line.

Furthermore, the servitudes concerned the lines crossing the servient land, not the substations located at either end of those lines. The Supreme Court found nothing in the words of the agreements that would explicitly or implicitly prevent Hydro-Québec from redirecting one of its lines toward another substation. The right to operate electrical transmission lines includes the right to make modifications such as the one that was made in the reconfiguration of the Jacques-Cartier–Duvernay line.

ALBERTA COURT OF APPEAL

***Cartwright v Rocky View County Subdivision and Development Appeal Board,* 2020 ABCA 408**

Municipal Law - Real Property - Reasonable Apprehension of Bias

In this decision, the ABCA allowed an application for the admission for fresh evidence and allowed the appeal by Chloe Cartwright (the "Appellant") from the Decision of The Rocky View County Subdivision and Development Appeal Board ("SDAB") dated August 22, 2019 (2019-SDAB-037).

Statement of Facts

The Appellant was a rural landowner in Rocky View County ("the County"). In 2012, she filed an application to re-designate her land from Ranch and Farm to Business-Leisure and Recreation. The County re-designated the land and, in 2013, approved the Appellant's development permit. The Appellant later allowed this development permit to expire.

In December 2018, the Appellant applied for a new development permit. A development permit was approved by the Development Authority on May 28, 2019. The application had been circulated to adjacent landowners and the issued development permit was appealed by three adjacent landowners.

The appeal of the Appellant's development permit was the seventh matter on the SDAB's June 26, 2019 hearing list. Chairperson Kochan participated in the first six appeals. Prior to the commencement of the seventh appeal, however, he announced his intended recusal and stated that a close relative was going to support the appeal. He further stated that he would speak on behalf of supporting the appeal.

Application to Adduce Fresh Evidence

At the commencement of the appeal, the Appellant made an application to adduce fresh evidence to strengthen her argument of reasonable apprehension of bias and in particular Chairperson Kochan's conduct.

The ABCA noted that according to section 689(1) of the *Municipal Government Act* ("*MGA*"), upon hearing an appeal from the decision from a subdivision and development appeal board "no evidence other than the evidence submitted to the Municipal Government Board or the subdivision and development appeal board may be admitted...". However, the ABCA found that a strict literal interpretation would insulate some important errors of law from the review on appeal. As this could not have been intended, the ABCA allowed the application to adduce fresh evidence.

Analysis

The Appellant was given permission to appeal the Decision on the following two grounds:

(a) Did the conduct of the appeal give rise to a reasonable apprehension of bias?

(b) To what extent can the Respondent (SDAB) consider "agriculture" regarding decisions with respect to a parcel that by way of site-specific amendment to a Land Use Bylaw has been re-designated from "Agricultural Land" to another use such as "Business-Pleasure and Recreation"?

Reasonable Apprehension of Bias

The ABCA noted that the test to determine if apprehension of bias had been established was whether an informed person, viewing the matter realistically and practically, would have had a reasonable apprehension of bias. In the case of administrative tribunals, the context must be considered. It noted that the basis for a reasonable apprehension of bias must be substantial and the matter should not be decided by a particularly sensitive or scrupulous person.

The ABCA restated *Stubicar v Calgary (Subdivision and Development Appeal Board), 2019* ABCA 336. There the ABCA had stated that SDABs are adjudicative tribunals and the conduct of their members must not create a reasonable apprehension of bias regarding their decisions. This was a contextual assessment and took into account the nature of the tribunal and the nature of the decision being made.

The ABCA considered *Beaverford v Thorhild (County) No 7, 2013* ABCA 6 in finding that SDAB members were known to declare a position, even if it was outside the context of hearing a specific matter. The ABCA found that the creation of a reasonable apprehension of bias was not automatically created by the participation of a person who had previously expressed a relevant opinion. The Court found that the context of the decision had to be considered.

The ABCA found that, while Kochan did not participate in the hearing, he had made his position, concerning the appeal, clearly known while he was still in the position of chairperson and he then advocated for the appeal. Further, the ABCA noted that Kochan chose to advocate for himself and his family, while there were likely qualified people who could have represented him.

The Appellant argued that Kochan’s conduct tainted the entire proceeding before the SDAB.

The ABCA found that a plain and ordinary reading of the *Code of Conduct* indicated that Kochan should not have been permitted to advocate before the SDAB once he recused himself. Schedule B of the *Code of Conduct* addresses pecuniary interests. A Member has a pecuniary interest if the Member’s Family could be monetarily affected by a matter. Where a Member had a pecuniary interest, Section 5 of Schedule B of the *Code of Conduct* dictates specific requirements of the Member. These requirements include that the Members must be absent from the room in which the matter is being heard, except, as emphasized by the ABCA, to the extent that the Member is entitled to be heard before a Board or a Committee as Appellant or a person affected by the matter before the Board or Committee.

The ABCA found that, as Kochan had a daughter who stood to be monetarily impacted by the Appellant’s development permit, he had a pecuniary interest. He was therefore subject to the conditions of Section 5 of Schedule B of the *Code of Conduct.*

The respondent relied on s 687(1)(d) of the *MGA* in arguing that the board was required to hear from individuals in Kochan’s position. This section states that at a hearing under section 686, the SDAB must hear any person who claims to be affected by the permit and that the SDAB would agree to hear, or a person on behalf of that person.

The ABCA found the respondent's argument to fail. First, it does not make logical sense that the Code of Conduct would attempt to protect against a reasonable apprehension of bias by requiring a board member to leave the room when a pecuniary interest exists (such as a familial connection), but that the Act would allow that same person to make representations to the board on behalf of a family member. Second, a logical reading of s 687(1)(d) of the *MGA* indicated that the board can exercise discretion in determining from whom it hears. Were this discretion non-existent, the words “and that the subdivision and development appeal board agrees to hear” would cease to have meaning. The presence of discretion thus tempers the use of the word “must” in *MGA* s 687(1).

Kochan’s conduct was contrary not only to the Rocky View County *Code of Conduct* and the *Act*, which prohibited him from being involved in the matter under their pecuniary interest provisions but also under the common law doctrine of reasonable apprehension of bias.

The ABCA found that a reasonable apprehension of bias had arisen from Kochan’s conduct, as a chairperson, he was an individual in a position of power and influence. While there was no evidence of actual bias in the Decision, under the circumstances, it was only relevant that a reasonable apprehension of bias existed. The ABCA found that, as this reasonable apprehension of bias existed, the Decision could not stand.

To What Extent Can The SDAB Consider "Agriculture" With Respect To A Decision Regarding A Parcellate By Way Of Site-Specific Amendment To A Land Use Bylaw Which Has Been Re-designated From "Agriculture Land" To Another Use Such as "Business-Leisure and Recreation"?

The Appellant argued that since the Rocky View Council had passed a site-specific *Bylaw* amendment wherein the land was changed from "Agriculture Land" to "Business-Leisure and Recreation", those who supported the appeal against the issuance of the development permit were focused on an inappropriate factor, namely agriculture.

The respondent argued that the Appellant's proposed development was a discretionary use: section 683 of the *MGA*. As such, a discretionary use is a use for which an applicant has no automatic right to a permit. The SDAB may decline to issue a development permit for a discretionary use if, based on sound planning principles, the use is judged inappropriate in specific circumstances due to its adverse effect on new properties. According to the respondent, the Appellant remained obligated to apply for a development permit before commencing any development on her land.

In the ABCA's opinion, merely referencing agricultural concerns as it impacts the property of others does not in and of itself represent a collateral attack upon the *Bylaw* amendment. The ABCA found the SDAB did not err in considering these submissions.

The ABCA dismissed this ground of appeal.

<u>Conclusion</u>

The ABCA quashed the decision from the SDAB, 2019-SDAB-037. The matter was remitted back to an entirely differently constituted panel of the SDAB for rehearing. Furthermore, none of the members of the SDAB that were present on June 16, 2019, or August 7, 2019, were to sit on the re-hearing.

***Dorin v EPCOR Distribution and Transmission Inc.,* 2020 ABCA 391**
AUC Jurisdiction

In this decision, both a Majority (Crighton, J.A. and Pentelechuk J.A) and Minority (O'Farrall J.A.) of the Alberta Court of Appeal dismissed the appeal from Mark Dorin (the "Appellant") on a question of law and/or jurisdiction that arose from the Appellant's interpretation of section 4(2) of the *Edmonton Restricted Development Area Regulations*, Alta Reg 287/1974 ("*ERDAR"*), which provides as follows:

> 4(2) No Minister of the Crown, government official or government agency shall, without the written consent of the Minister of Infrastructure, exercise any power under the *Municipal Government Act*, *the Pipe Line Act*, the *Water Resources Act* or any other Act to order, authorize, approve, permit or consent to any operation or activity that causes, is likely to cause or will cause a surface disturbance of any land in the Area, or issue or cause to be issued any order, authorization, approval, permit, licence or consent instrument for that purpose.

The Appellant challenged the AUC's jurisdiction to enter into inquiries relative to EPCOR's application, including conducting a hearing, on grounds the Minister of Infrastructure had not yet provided written consent for the project to be located in the transportation utility corridor (the "TUC").

The AUC concluded that it had jurisdiction to consider and approve EPCOR's application so long as EPCOR provided to it a written consent from the Minister of Infrastructure for the construction and operation of the project within the TUC.

Upon receipt of the Commission's decision on the question of jurisdiction, the Appellant ceased participating in the process. The project was approved by the Commission, the Minister's consent was provided to EPCOR under s 5(2)(b) of the *Edmonton Restricted Development Area Regulations*, and the necessary permits and licences were issued to EPCOR to begin construction of the substation.

The Appellant did not seek judicial review of the Minister's consent, nor did he apply for a stay of the Commission's decision. The Court of Appeal noted that the Substation has now been constructed and is operational.

Findings of the Majority

The Majority found that the issue between the parties was moot. The Majority further noted that it was not persuaded that the question was evasive of review. More importantly, the Majority noted that it declined to interpret s 4(2) of the *ERDAR* without notice to and possible participation of the Minister.

Even if an error of law occurred in the order in which permission was granted in this case (which the Majority declined to determine), the Majority was satisfied no substantial wrong or miscarriage of justice has occurred and no significant prejudice had been experienced by any party.

Findings of the Minority

The Minority found that two separate and distinct ministerial consents were required under the *ERDAR*: consent to the AUC under s 4(2) before the AUC exercises any of its "statutory power" and before it issues any approval, permit or license; and consent to EPCOR under s 5(2)(b) before the commencement of any activity likely to cause a surface disturbance of land in the area.

Because of the location of the substation and because the construction of the substation involved an activity that would cause a surface disturbance of land within the Edmonton Restricted Development Area ("RDA"), the Minority found the AUC was unable to exercise its powers under the *AUC Act* or the *Hydro and Electric Energy Act* to hear or approve any applications involving surface-disturbing activities in the RDA without the written consent of the Minister of Infrastructure according to section 4(2) of the *ERDAR* made according to the *Department of the Environment Act* and later according to the *Government Organization Act.* The AUC did not receive the required consent from the Minister.

The respondent, EPCOR, was likewise prohibited by the *ERDAR* regulations from commencing construction of the substation and associated transmission line connections without the written consent of the Minister. EPCOR did receive the written consent of the Minister to construct and operate the substation after the AUC approved it.

However, the Minority found that the AUC's failure to obtain the Minister's consent to the exercise of its power to approve the substation did not adversely affect or prejudice the rights of the Appellant.

The Minority noted that Rule 14.75(2) of the *Alberta Rules of Court* provided that the Court of Appeal may dismiss an appeal despite an error of law where no substantial wrong or miscarriage of justice had resulted or where a decision would have been the same despite the error or where, despite the irregularity, no significant prejudice had been experienced by any party. The Minority found all the requirements of this rule had been met in this case, and dismissed the appeal.

ALBERTA ENERGY REGULATOR

***Invitation for Feedback on Revisions to Directive 20*, AER Bulletin 2020-23**

Bulletin

After a multiyear study, the AER published *Open File Report 2019-06: A Risk-Based Methodology for Commingled Well Abandonment – Southeastern Alberta Gas Field Case Study*. Based on the findings of that study, the AER released Bulletin 2020-20 on September 17, 2020, to inform licensees that the AER had commenced accepting nonroutine requests to abandon commingled wells.

The AER has now made changes to section 5 of *Directive 020: Well Abandonment* to allow for some routine abandonment of commingled wells that involve qualified subsurface geological strata and corresponding geographic locations. Information on qualified pools will be made available on the *Directive 020* webpage. The AER is now seeking public feedback on this revision.

***Invitation for Feedback on Proposed Changes to the Pipeline Rules*, AER Bulletin 2020-24**

Bulletin

The AER sought feedback on proposed changes to the *Pipeline Rules*. The rules were made by the AER under the authority of the *Pipeline Act*. The rules were last reviewed and updated in 2005.

The changes include modernizing them to align with the latest safety and integrity management standards set by the Canadian Standards Association, reducing the environmental footprint of pipelines, reducing the administrative burden on pipeline operators, and aligning the rules with pipeline safety recommendations made by the Auditor General in 2015.

The Bulletin provided a summary of proposed changes, and asked stakeholders to provide feedback by completing a comment form and providing it to the AER by January 15, 2021.

ALBERTA UTILITIES COMMISSION

Amendments to AUC Rule 017 Including Streamlining Requirements, **AUC Bulletin 2020-35**

Bulletin

On November 6, 2020, the amendments to Rule 017: *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission*, which were approved on October 19, 2020, came into effect.

Background

The AUC initiated a rule review process in July 2020, seeking feedback from stakeholders on changes to Rule 017. Proposed changes involved the removal of references to the capacity market, the introduction of a new section that would permit the Alberta Electric System Operator ("AESO") to streamline its consultation and application process for making administrative changes to existing ISO rules, and the removal of numerous mandatory requirements in the rule.

To address the concerns expressed by stakeholders regarding the responsiveness from the AESO, the AUC will be keeping the requirements for the AESO to provide a copy of any data, analyses or other material that the AESO considers to be relevant to the need for, the development of, removal of, or renewal of a proposed rule (section 4.3(b) of Rule 017) and provide written responses to the submissions of stakeholders (section 5.3 of Rule 017) early in the consultation process.

AUC Moves to Reduce Regulatory Burden and Improve Efficiency with Rule Amendments, **AUC Bulletin 2020-36**

Bulletin

The AUC has proposed amendments to Rule 003: *Service Standards for Energy Service Providers* that would:

- Remove the requirement to submit call center and billing performance data;
- Remove the requirement to submit customer satisfaction data;
- Remove the quarterly reporting requirements; and
- Focus and streamline the reporting requirements on the performance of regulated service providers through three types of reporting requirements:

    (1) Annual performance reports: restructured to remove prescriptive reporting requirements to allow regulated service providers the discretion to report how their customer care and billing operations and processes are structured to align with their customers' expectations of service quality;
    (2) Unexpected event reports; and
    (3) Material change reports.

Among the reasons for the removal of these reporting requirements is the introduction of Rule 032: *Specified Penalties*, in 2019. Rule 032 provides the AUC with the ability to address billing-related matters in particular, and customer experience matters in general, in a more efficient and timely manner than the reporting under Rule 003 is able to.

The Commission's review of Rule 003 will consist of a stakeholder consultation involving a written process.

***Amendment to AUC Rule 027,* AUC Bulletin 2020-37**
Bulletin

On November 19, 2020, Rule 027: *Specified Penalties for Contravention of Reliability Standards* came into effect in its amended form. Rule 027 was amended to reflect a revision to the naming of an Alberta reliability standard PRC-005-AB1-6 to PRC-005-AB2-6, that came into effect on October 13, 2020.

***The AUC Moves to Reduce Regulatory Burden and Improve Efficiency with Rule 021 and Rule 028,* AUC Bulletin 2020-38**
Bulletin

The AUC has proposed amendments to Rule 021: *Settlement System Code Rules* and Rule 028: *Natural Gas System Settlement Code* that would:

- Remove the Pre-final error correction process requirement from both rules;
- Remove the USA transaction requirement from both rules; and
- Clarify the time frequency of requirements from meter data managers in Rule 021.

The AUC's review of rules 021 and 028 will consist of a stakeholder consultation involving a written process.

***Proposed Amendments to AUC Rule 002 Will Reduce Regulatory Burden and Improve Efficiency,* AUC Bulletin 2020-39**
Bulletin

The AUC has proposed amendments to Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors* that would:

- Replace quarterly reporting requirements with semi-annual reporting requirements.
- Reduce other reporting requirements.

The AUC's review of Rule 002 will consist of a stakeholder consultation involving a written process.

***Reducing Regulatory Burden: Checklist Applications for Certain Abbreviated Needs Identification Document Applications,* AUC Bulletin 2020-40**
Bulletin

The pilot project for low-risk electric transmission and gas utility pipeline applications launched in Bulletin 2020-15 will be expanded to include abbreviated needs identification document applications that are driven by system access service requests from generators and non-distribution facility owner loads.

Abbreviated needs identification documents would be eligible to be filed as a checklist, if:

- All stakeholder concerns were resolved;
- There were no system-related costs;
- The project would not result in any Category A adverse system impacts under the Alberta Reliability Standards;
- The project was not anticipated to cause significant environmental effects;

- The alternative selection is straightforward or obvious. [The Alberta Electric System Operator ("AESO") has a compelling rationale for why one technical solution is superior.]

During the pilot project, the AESO will be required to file a two-page checklist confirming that the regulatory requirements for the application have been met, a cost estimate, and a single-line diagram. The AESO will not be required to file any other related supporting documents; however, it will be required to keep the related supporting documents on file to respond to an AUC compliance review.

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

The AUC prepared a form for the checklist applications. The abbreviated needs identification document checklist application form was made available on Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* Rule-related information page on the AUC website.

Alberta Electric System Operator 2019 Deferral Account Reconciliation, **AUC Decision 25768-D02-2020**
AESO - Deferral Account Shortfall

In this decision, the AUC approved the request from the Alberta Electric System Operator ("AESO") to settle its 2019 net deferral account shortfall with market participants, of $41.6 million.

Introduction and Application Details

In July 2020, the AESO filed its application for approval of its 2019 deferral account reconciliation ("DAR") and for changes to the deferral account balances for 2018 to 2012. The deferral account balance resulted from differences between costs the AESO had incurred in providing system access service ("SAS") and the revenues recovered in rates charged to market participants in prior periods. The AESO requested approval of its determination and allocation of a $41.6 million net deferral account shortfall.

The AESO also requested approval to settle the amounts for the 2019 deferral account balance on an interim and refundable basis, subject to adjustment in the final decision to facilitate immediate settlement of the deferral account amounts with market participants.

Methodology, Allocation and Settlement of Deferral Account Balances

The AESO noted that this application relied on the approval granted by the AUC in Decision 22942-D02-2019 to apply the revised DAR methodology for production years 2017 and onward.

The AESO explained that the allocation of deferral account balances and adjustments were implemented through its continued use of a software program that it developed to calculate DARs. This approach was consistent with its previous DAR applications.

The AESO submitted that after the allocation of deferral account balances is determined by rate and rate component for each market participant, additional revenue already settled through Rider C or in prior DARs with each market participant would be subtracted or added by rate and rate component. The remaining balance would be the amount of the deferral account charge or refund attributed to the market participant on a production month basis, by rate and rate component.

The AESO proposed to settle the outstanding deferral account balances through a one-time payment and collection option and, similar to past reconciliation applications, it offered a three-month payment option, including carrying charges, if the one-time payment option presented a financial burden to market participants.

AUC Findings

The AUC reviewed the AESO's methodology and found that it is consistent with the methodology approved for DAR applications in Decision 22942-D02-2019. It also reviewed the allocation of the deferral account balances and found that it is consistent with previously approved DAR applications and with the 2018 ISO tariff. The AUC approved the AESO's methodology, allocation and settlement of the deferral account balances.

Cost Variances

The AUC noted that this application represented the first opportunity to consider the actual, recorded AESO revenue requirement costs for the year 2019, and the first opportunity to consider cost variances for the years 2018 through to 2012 concerning the recorded cost amounts for those years, after the AUC's assessment in Decision 24910-D01-2019. The costs and cost variances applied for in the application were summarized in Table 1 below:

Table 1. Recorded costs and cost variances subject to assessment in the application

	Deferral account reconciliation				
Component	**2019 recorded costs**	**2018 cost variances**	**2017 cost variances**	**2016 cost variances**	**2015 to 2012 cost variances**
Costs paid	**($ million)**				
Wires	(1,850.2)	0.2	(31.4)	(8.4)	16.8
Ancillary services	(213.0)	0.1	(0.0)	-	-
Other industry	(15.4)	-	-	-	-
General & administrative	(97.1)	-	-	-	-
Total costs paid	(2,175.6)	0.3	(31.4)	(8.4)	16.8

Source: Exhibit 25768-X0002, Table 2-5.

As set out by the AUC in Decision 2014-242, there are four principal categories of costs and expenses incurred by the AESO in its tariff:

AESO's Administrative Costs and Ancillary Costs

No issues were raised by interested parties regarding the AESO's own administrative costs or its ancillary costs. The AUC accepted these costs as submitted by the AESO.

Transmission Line Losses

The AESO did not include the reconciliation of transmission line loss amounts in the application. This is consistent with the approach taken in previous DAR applications, given that effective January 1, 2006, the cost of transmission system losses was no longer subject to the retrospective DAR.

Costs Related to Transmission Wires Payable Under a TFO Tariff

Regarding transmission facility owner ("TFO") wires-related costs and cost variances, the AUC found that the AESO must pay the rates set out in the approved tariff of the owner of each transmission facility according to Section 32 of the *Electric Utilities Act* ("*EUA*"). The AUC approved the costs and expenses of a TFO in the TFO's applicable tariff application, according to Section 122 of the *EUA*. The costs and cost variances submitted by the AESO for TFO wires-related costs were approved as filed.

Deferral Account Amounts

The AESO identified a net shortfall of approximately $41.6 million (net of Rider C charges and refunds, and any prior DAR settlements) to be allocated to customers, composed of the following amounts:

	Deferral Account Reconciliation					Totals
Component	2019	2018	2017	2016	2015 to 2012	2019 to 2012
Net (Shortfalls) Surplus ($ million)	(15.9)	(1.6)	(32.0)	(8.9)	16.8	(41.6)

The AUC accepted the accuracy of deferral account amounts and the calculation of the net deferral account shortfall of $41.6 million. The AUC approved the deferral account balances and the net deferral account shortfall amount of $41.6 million.

***AltaLink Management Stage 2 Review and Variance of Decision 23848-D01-2020 AltaLink Management 2019-2021 General Tariff Application,* AUC Decision 25870-D01-2020**

Review and Variance - Salvage

In this decision, the AUC varied findings from Decision 23848-D01-2020 (the "Decision") and approved the net salvage method proposed by AltaLink Management Ltd. ("AltaLink").

Introduction

AltaLink proposed to change its method for collecting net salvage costs related to the retirement of its utility assets in its 2019-2021 general tariff application ("GTA"). In the Decision, this proposal was denied by the majority hearing panel. AltaLink subsequently requested a review and variance ("R&V") of the Decision. The AUC issued Decision 25769-D01-2020 and granted the second stage review proceeding to re-examine AltaLink's proposed net salvage method.

Proposed Net Salvage Method

Views of Interveners

The United Consumer Advocate ("UCA") supported the proposed net salvage method submitting that the traditional approach to net salvage was no longer working. Further, the UCA submitted that AltaLink's proposal should be approved in light of evidence that it reflected a widely used and well-accepted approach to managing the costs of net salvage both in other jurisdictions and in Alberta, and would be more consistent with a fair allocation of the real value of assets over time.

The Consumer's Coalition of Alberta ("CCA") opposed the proposed net salvage method. The CCA submitted that the transfer of net salvage costs to future ratepayers, who would receive minimal benefit from the use of the assets, was the most significant reason why AltaLink's proposal should be denied.

Views of AltaLink

AltaLink argued that the deepening of the COVID-19 crisis, oil price shock, and accompanying economic turmoil, all of which occurred after the issuance of the Decision, had made the basis for approving its proposed net salvage method even more compelling. AltaLink submitted that its proposed net salvage method represented a long-term and principled solution to both the immediate need for customer rate relief and to the broader issue of transmission rate levelization following the "big build."

Stage 2 Panel Findings

(a) Testing of AltaLink's Net Salvage Method and Demonstration of Near-Term Rate Relief

The Stage 2 Panel agreed with the conclusions in Bulletin 2016-16, i.e. that alternative approaches and rate treatments to mitigate or smooth the effect of rate or bill increases on consumers should be considered on a case by case basis in the context of comprehensive tariff applications. Accordingly, the Stage 2 Panel found that consideration of AltaLink's proposed net salvage method was properly within the context of a comprehensive GTA such as Proceeding 23848.

Regarding the demonstration of near-term rate relief, the Stage 2 Panel agreed with the majority hearing panel that the proposed net salvage method would benefit existing customers by materially reducing AltaLink's revenue requirement in the forecast period.

The AUC highlighted AltaLink's calculations that recalculating its 2019-2021 revenue requirement assuming approval of its proposed net salvage method would result in lower salvage collections in the amounts of $37.1 million, $34.5 million, and $30.3 million for the years 2019, 2020 and 2021, respectively, compared to the amounts approved in Proceeding 25627 of $61.2 million, $62.7 million and $64.4 million.

Also, the Stage 2 Panel noted that, assuming the proposed net salvage method was approved, the reduction to AltaLink's revenue requirement for the years 2019, 2020 and 2021 would be $23.6 million, $26.7 million and $31.2 million, respectively, resulting in materially lower revenue requirements.

(b) Intergenerational Equity and the Premise of AltaLink's Proposed Net Salvage Method

The Stage 2 Panel found that, on balance, the proposed net salvage method would afford equitable intergenerational treatment for both current and future ratepayers for whom the transmission system was built to serve. This was because, based on AltaLink's submissions, in the absence of another "big build," future customer rates would likely reflect reduced levels of undepreciated transmission capital costs, and the costs would be borne over a greater expected customer load base compared to current customers. This was notwithstanding that AltaLink's proposed net salvage methodology would result in the deferral of salvage costs into the future, either in the form of a capitalized asset or as an operations and maintenance cost.

The Stage 2 Panel found that, given the unprecedented economic effect of the COVID-19 pandemic on ratepayers, and the potential for AltaLink's proposal to provide urgently needed relief in the current test period, significant weight must be attributed to near-term interests.

(c) Ability of AltaLink to Proceed with the Proposed Net Salvage Method

The Stage 2 Panel found that AltaLink's proposed net salvage method was otherwise principled, based on AltaLink's submissions that it was financially able to implement the proposed net salvage method, notwithstanding the effects of COVD-19; that adopting the proposal would not impact its credit rating, assuming certain parameters; and that Alberta's load growth was expected to recover in the mid to long term. The Stage 2 Panel relied on AltaLink's confirmations that it remained financially able to proceed with its proposed net salvage method over the test period and that the viability of the proposal applied to both economic downturns and uptrends.

(d) AltaLink's Agreement with UCA Recommendations 3-8

The Stage 2 Panel noted that AltaLink accepted the UCA's recommendations 3-8, regarding implementation aspects and future GTAs. AltaLink agreed to record and track costs of removal related to the retirement of an asset, whether to be capitalized to the cost of a replacement asset or recorded in association with a terminal asset retirement. AltaLink further confirmed that the implementation of changes to its process for recording and tracking of cost of removal would be sufficient information for AltaLink to return to the traditional method of net salvage on a prospective basis, where the capitalization of historical salvage amounts would be unchanged.

AltaLink further confirmed that specific amounts of net salvage to be included in revenue requirements for each year would be tested and approved in future GTAs. AltaLink was not seeking advance rulings on the prudency of any cost of removal. AltaLink agreed that the prudence of any cost of removal, whether to be capitalized or recorded in association with a terminal asset retirement would be included in future revenue requirement for collection from customers subject to testing within future direct assigned capital deferral account applications and GTAs.

(e) Stage 2 Panel Clarifications Concerning AltaLink's Proposed Net Salvage Method

The Stage 2 Panel provided the following clarifications concerning AltaLink's proposed net salvage method implementation, tracking, and ongoing operation.

- The Stage 2 Panel accepted that the measure by which AltaLink would determine the amount of net salvage expense to recover through depreciation expense during the period of transition is linked specifically to funds from operation ("FFO")/Debt of 11.1 per cent for the test years. However, the Stage 2 Panel directed that this measure would be subject to testing in future GTAs in terms of both substance and form.

- AltaLink was directed to maintain enough information to revert to its traditional net salvage method at any point in the future. The requirement to maintain this information considered the implications of AltaLink's statement that a return to the traditional method of salvage would be on a prospective basis, where the capitalization of historical salvage amounts would be unchanged. AltaLink was directed to, in each future GTA or direct assigned capital deferral account ("DACDA"), report by a uniform system of account, both the forecast and actual costs of removal that had been recorded to the net salvage reserve account during the period of transition, capitalized or recorded in association with a terminal asset retirement.

- The Stage 2 Panel directed that if the balance in the net salvage reserve account becomes insufficient to meet the anticipated costs of removal associated with terminal asset retirements, AltaLink would be required to propose the manner and period of collection of those costs in that GTA or DACDA. AltaLink was directed to provide a continuity schedule for its net salve reserve account in each future GTA on both a forecast and actual basis.

- AltaLink was directed to, in each future GTA or DACDA, provide detailed information to test the prudency of costs of removal whether recorded to the net salvage reserve account during the period of transition, capitalized to the cost of a replacement asset, or recorded in association with a terminal asset retirement.

Anomaly Adjustment Applications in Rebasing the 2018-2022 Performance Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, **AUC Decision 25422-D01-2020**
Rates - Anomaly Adjustment

In this decision, the AUC considered the anomaly adjustment applications ("Anomaly Applications") filed by AltaGas Utilities Inc. ("AltaGas"), ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. (the "ATCO Utilities"), ENMAX Power Corporation ("ENMAX") and FortisAlberta Inc. ("Fortis") (together referred to as the "Utilities") and The City of Calgary ("Calgary"). The Anomaly Applications aimed to adjust the going-in rates for the 2018-2022 performance-based regulation ("PBR") plans of the Utilities.

The AUC approved ENMAX's retirement anomaly as applied for and denied the other anomaly adjustments applied for by the Utilities and Calgary. ENMAX was directed to update its 2021 PBR rate adjustment application to account for the change of its 2018 going-in rates and K-bar by November 18, 2020.

Background

The AUC set out the rebasing methodology for the 2018-2022 PBR term in Decision 20414-D01-2016 (Errata). This methodology consisted of setting the Utilities' going-in rates based on a notional 2017 revenue requirement. The AUC determined that operations and maintenance ("O&M") and average actual retirements, as components of the notional 2017 revenue requirement could be adjusted for anomalies.

Anomaly Adjustments Applied for by the Utilities

The Utilities proposed various anomalies that would adjust the O&M component of the notional 2017 revenue requirement, including changes to the parameters used to convert the lowest O&M cost year to 2017 dollars and adjustments to account for labour escalation.

The AUC assessed the applied for anomalies to determined whether adjustments were required to enable the utility to continue to provide safe and reliable service to its customers and provide it with a reasonable opportunity to earn a fair rate of return.

Adjustments for Converting the Lowest O&M Cost Year Expenditure

(a) Proposed Adjustment to the I Factor

The AUC considered that the views advanced by the Utilities applying for a conversion adjustment were premised upon an underlying presupposition that the PBR inflation factor formula and the inputs, prescribed in Decision 20414-D01-2016 (Errata), are incorrect notwithstanding that no party sought to raise any issue with the methodology and inputs when it was approved. The AUC found that the appropriate time to challenge the methodology for setting going-in rates was after it was established in Decision 20414-D01-2016 (Errata).

The AUC noted that the question is whether an adjustment is required to the I factor used to convert the expenditures in the lowest O&M cost year for the purposes of rebasing. Having considered the evidence, the AUC could not conclude that this adjustment is required to enable those utilities that applied for such an adjustment to continue to provide safe and reliable service to their customers and give them a reasonable opportunity to earn a fair rate of return.

(b) Proposed Adjustment to the Alberta Average Weekly Earnings ("AWE") Index of the I Factor

In rebasing, the AUC had instructed the utilities to calculate the I factor by utilizing a lagged weighted average of the AWE and the consumer price index ("CPI").

The AUC found that the AWE and CPI indices are integral components of the I factor, which is an integral component of the rebasing methodology. As such, the AUC stated that the index prescribed in Decision 20414-D01-2016 (Errata) will not be adjusted, and denied AltaGas's application for an anomaly adjustment related to the labour cost index (AWE vs. fixed weighted index or "FWI") of the I component.

(c) Proposed Adjustment to X

The AUC did not accept the submission from ENMAX or AltaGas that the inclusion of the X factor in converting costs from a utility's lowest O&M cost year is similar to double counting. The AUC found that to calculate 2018 going-in rates based on a 2017 notional value, the X factor was required in the rebasing methodology.

The AUC did not find any evidence to suggest that the inclusion of the X factor in converting AltaGas and ENMAX's lowest O&M cost year expenditures to 2017 dollars was anomalous or could otherwise have impeded either utility's ability to provide safe and reliable service to its customers and have a reasonable opportunity to earn a fair return.

(d) Proposed Adjustments to Q

ATCO Electric and ENMAX applied for an anomaly related to Q. ATCO Electric proposed a Q of 0.4 per cent based on the expected customer growth using forecast 2017 to actual 2016 billing determinants instead of its approved 2017 Q of -2.7 per cent. ENMAX proposed a similar adjustment based on its average Q for the 2015-2016 time-period, which was 1.20 per cent, instead of its approved 2017 Q of -0.75 per cent. The AUC was not persuaded by these submissions from ATCO Electric and ENMAX.

(e) AUC Findings on the Proposed Adjustments for Converting the Lowest O&M Cost Year Expenditures to 2017 Dollars.

The AUC found that the AWE index and the FWI were integral parts of the conversion formula. The AUC found that the difference between these two labour indices that are components of I, the conversion to 2017 dollars calculation, the inclusion of the X factor and the calculation of Q based on the prescribed methodology used to convert the lowest O&M cost year expenditures to 2017 dollars are integral components of the conversion formula. The AUC noted again that the appropriate time to challenge the methodology for setting going-in rates was after it was established in Decision 20414-D01-2016 (Errata). No party had filed for review of that decision at that time. The AUC was not prepared to alter the conversion methodology in the current proceeding and was not persuaded that the applied-for anomalies were related to the application of the methodology rather than to the methodology itself. The AUC did not approve any of the applied-for anomaly adjustments that relate to fundamental I, X, or Q parameters of the conversion formula.

The AUC determined there was no evidence that the Utilities had been unable to provide safe and reliable service while having the opportunity to earn a fair return because of the conversion parameters used to calculate the O&M component forming 2018 going-in rates, of which the Utilities would have been aware since 2016. Accordingly, the AUC denied all proposed anomalies related to the PBR inflation factor formula and the inputs prescribed in Decision 20414-D01-2016 (Errata) to convert the lowest O&M cost year expenditures to 2017 dollars.

Proposed Labour Escalation Adjustments

The AUC did not consider unfavourable outcomes of labour negotiations, as suggested by Fortis and ENMAX, a valid reason for the adjustments proposed by Fortis or ENMAX to qualify as an anomaly for the purposes of rebasing. The AUC denied Fortis's and ENMAX's application for an anomaly adjustment related to a specific labour cost adjustment escalation rate.

Other O&M Adjustments Proposed by ENMAX

ENMAX applied for anomaly adjustments of $0.82 million for severance costs and $1.67 million to account for new staffing and initiatives required to transition to a new business environment. The anomaly adjustment for severance costs comprised $0.35 million for incremental regulatory resources and $1.31 million for new initiatives in cyber-security and data center transformation.

The AUC was not convinced that any of these requested anomaly adjustments were based on abnormal circumstances, and denied the applications for the corresponding anomaly adjustments.

Retirement Adjustment Proposed by ENMAX

ENMAX submitted that the $36.23 million retirement of the Wires Retail Access Program ("WRAP") in 2016 was anomalous and would result in a material impact of $15.32 million to its K-bar funding over the 2018-2022 PBR term. ENMAX proposed that the retirement of the WRAP be entirely excluded from the calculation of its 2018 base K-bar.

Based on submitted evidence, the AUC noted that the retirement of the WRAP in 2016 stood out amongst the retirements used to calculate ENMAX's retirement average. It was significantly larger than other retirements in the PG8 capital program retirements category and had a disproportionate effect on ENMAX's retirement average due, in part, to ENMAX's average having been based on only two years. The AUC accepted the application for an anomaly adjustment. The AUC determined that it was reasonable to reduce the contribution of the WRAP to the determination of the retirement average by 85 per cent (i.e., only 15 per cent of the WRAP retirement amount shall be used in the calculation of the retirement average). This would result in a retirement average that is closely aligned with ENMAX's 2004-2016 average. ENMAX was directed to update its 2021 PBR rate adjustment application accordingly by November 18, 2020.

2018-2022 K-Bar I Factor Adjustment Proposed by Fortis

In addition to requesting the I factor conversion adjustment of 0.91 per cent to establish the notional 2017 revenue requirement, Fortis also requested approval to apply this rate to determine the K-bar incremental capital funding for the 2018-2022 PBR term.

The AUC found no basis to expand the concept of anomaly adjustments to apply to K-bar funding. This extension would be inconsistent with the concept of an anomaly adjustment. Fortis's request to apply the 0.91 per cent in the calculation of its 2018-2022 PBR plan K-bar was denied.

Anomaly Adjustments Applied for by Calgary

Calgary sought adjustments to the going-in rates of the ATCO Utilities related to determinations made in Decision 20514-D02-2019. In that decision, the AUC directed specific reductions to the prices contained in the IT master services agreements ("MSA") between ATCO transmission and distribution utilities and Wipro Solutions Canada Limited ("Wipro") for inclusion in each of the regulated utilities' revenue requirements.

Calgary proposed a two-part anomaly it considered would take into account AUC-directed reductions to the prices contained in the IT MSAs between ATCO and Wipro. Calgary indicated that the two-part anomaly adjustment was designed to ensure that the 2018 going-in rates would reflect all ordered adjustments to Wipro prices from Decision 20514-D02-2019. It was further designed to ensure that customers would not pay for imprudent costs during the second term PBR.

The AUC observed that Calgary's anomaly application in the current proceeding sought relief similar to, if not the same as had been previously sought and rejected. The AUC disagreed with Calgary's argument that the proposed IT anomalies were required, in addition to the X factor, to ensure the intended incentives under PBR. The AUC denied Calgary's applied-for anomalies.

***ATCO Electric 2019 Annual Transmission Access Charge Deferral Account True-Up*, AUC Decision 25800-D01-2020**

AESO Tariff

In this decision, the AUC approved the application from ATCO Electric Ltd.("AE") for its 2019 annual transmission access charge ("TAC") deferral account true-up and carrying costs on the true-up amounts under Rule 023: *Rules Respecting Payment of Interest*. The AUC approved the collection of the 2019 TAC deferral account true-up amount of $6.482 million through a Rider G.

Introduction and Background

AE applied for the net 2019 TAC deferral account true-up collection of $6.482 million from customers.

Under the provisions of the performance-based regulation ("PBR") framework approved in Decision 2012-237, and subsequently adopted for the 2018-2022 PBR term in Decision 20414-D01-2016 (Errata), AE's TACDA is a dollar-for-dollar flow-through of the Alberta Electric System Operator ("AESO") tariff charges.

2019 TAC Deferral Account True-Up Amount and Rider G Rate

The total applied for true-up amount of $6.482 million included the following components:

Component	True-up Amount Collection/(Refund) ($ million)	Methodology to Attribute the True-Up amount to Rate Classes
2017 TAC deferral account true-up	0.574	Determined as the difference between the amount approved for collection or refund by rate class and the amount actually collected or refunded for each rate class.
2019 system access service ("SAS") deferral true-up	0.324	AESO costs were allocated to rate classes using AE's Phase II cost-of-service methodology underlying its SAS rates, except for Rate T31 for transmission direct-connect customers. Since Rate T31 customers are billed on a flow-through basis, no amounts were allocated to this customer class.
2019 AESO deferral account reconciliation ("DAR") true-up	6.778	Allocated to the rate classes based on total revenue collected, excluding Rate T31.
2019 Balancing Pool adjustments true-up	(1.219)	Allocated to all customers in proportion to the Balancing Pool amount collected or refunded in a year by rate class, except for Rate T31.
Carrying costs	0.025	Allocated to the rate classes in proportion to their deferral balances (for which carrying costs had been assessed) allocated to them in the preceding components of this true-up calculation.
2019 TAC deferral account true-up	**6.482**	**Calculated as the sum of true-up amounts and related carrying costs**

AUC Findings

The AUC found the application and schedules to have been consistent with the harmonized framework approved by the AUC in Decision 3334-D01-2015 and that the amounts composing the 2019 annual TAC deferral account true-up were reasonable. The AUC further found AE's assignment of the individual components to rate classes to have been reasonable in the circumstances and consistent with previously approved methodologies. The AUC approved the net collection of $6.482 million by AE.

As previously directed by the AUC, AE identified the under-frequency load shedding credit amounts separately and calculated carrying costs based on the weighted average Bank of Canada monthly bank rate in months in which the interest rate changed the under-frequency load. The AUC directed AE to continue this method in its next TAC deferral account true-up application.

The AUC found that AESO DAR amounts should not be included in the calculation and allocation of carrying costs if there are no carrying costs assessed on the AESO DAR amounts. AE was accordingly directed to exclude the AESO DAR amounts from the calculation and allocation of carrying costs in future TAC deferral account true-up proceedings where carrying costs would not be assessed on the AESO DAR.

Rider Implementation Period and Customer Bill Impacts

AE proposed that its 2019 annual TAC deferral account true-up Rider G be in effect from January 1, 2021, to December 31, 2021.

The AUC reviewed the total bill impacts of the proposed Rider J and noted that rate shock would be unlikely, as the typical bill changes were below the 10 per cent threshold, which had previously been used as an indicator of rate shock. The two rate classes above the 10 per cent threshold (rate classes D25 and D61 investment) were both seasonal rate classes and the bill impacts would be addressed in AE's 2021 annual PBR rate adjustment filing, under review in Proceeding 25864.

Rider G Rate

Rider G Rates would be affected by the total true-up amount, related carrying costs, and the implementation period of the rider.

The AUC accepted AE's proposal to calculate the Rider G Rate using the 2021 forecast billing determinants. The AUC noted that, in making this determination, it had been mindful that the 2019 rider would eventually be trued up to ensure the approved amounts were collected from, or refunded to, customers. The AUC approved AE's Rider G per rate class, as suggested by AE, effective January 1, 2021.

Combining Annual TAC Deferral Account Applications with the Annual PBR Rate Adjustment Filings

The AUC directed AE to include its 2020 TAC deferral account true-up application and supporting materials as part of its 2022 annual PBR rate adjustment filing. As part of that proceeding, the AUC would evaluate the effectiveness of such an approach to reduce the administrative burden and enhance regulatory efficiency and would, based on its review, consider adopting it for all future TAC deferral account applications.

***Barlow Solar Park Ltd. Corrigenda to Decision 25690-D01-2020*, AUC Decision 25690-D01-2020 (Corrigenda)**

Facilities - Solar Generation

In this decision, the AUC issued a corrigendum to Decision 25690-D01-2020. The AUC approved the application from Barlow Solar Park Ltd. to construct and operate a 27-megawatt solar power plant, designated as the Barlow Solar Park, in the City of Calgary (the "Project").

In Decision 25690-D01-2020, the Commission included a condition of approval related to Rule 033: *Post approval Monitoring Requirements for Wind and Solar Power Plants*. The condition was imposed in error because Alberta Environment and Parks ("*AEP*") did not prepare a renewable energy referral report for the Project given its specific circumstances and it neither required nor recommended post-construction monitoring.

Decision 25690-D01-2020 also stated in error that ENMAX Power Corp ("ENMAX") had "… confirmed its willingness to connect the power plant to ENMAX's 25-kilovolt electric distribution system provided that Barlow Solar can demonstrate compliance with applicable rules, standards and ENMAX's interconnection requirements." No connection voltage was stipulated by ENMAX.

Decision 25690-D01-2020 was amended to remove the Rule 033 condition as well as the specific reference to ENMAX's 25-kilovolt distribution system.

***City of Calgary Water Supply Agreement with Foothills County,* AUC Decision 25911-D01-2020**

Rates - Water Services

In this decision, the AUC approved the application from the City of Calgary ("Calgary") for a water supply agreement between it and Foothills County ("Foothills") for at least five years according to section 30(1) of the *Municipal Government Act* ("*MGA*").

Discussion and Findings

Calgary and Foothills agreed to enter into a new agreement providing that Calgary supply potable water and sanitary sewer service to Foothills (the "Service Agreement").

The AUC determined that, as section 30(1) of the *MGA* explicitly mentioned water, but did not reference wastewater, the AUC's jurisdiction was limited to aspects of the service agreement that pertained to water services. Accordingly, the AUC's findings in this decision related only to the supply of potable water under the service agreement, not wastewater.

Schedule G of the Service Agreement provided, among other things, that the usage rates and fees for water services would be determined based on guiding principles approved by Calgary City Council, including a cost of service basis. Schedule G of the Service Agreement also provided that the principles and practices used to determine usage rates and fees could be changed by way of amendments to Schedule G or by the findings or directives of the AUC according to its decisions and orders.

The AUC was satisfied that the service agreement between Calgary and Foothills, as it related to the supply of potable water, was necessary and proper for public convenience and properly served the public interest. On that basis and noting the absence of any objection to the application pursuant to section 30(1) of the *MGA*, the AUC approved the potable water supply agreement, as filed.

Commission-Initiated Review and Variance of Decision 22942-D02-2019, **AUC Decision 24932-D01-2020**
Review and Variance - Contributions in Aid of Construction

In this decision, the AUC decided to vary findings made in Section 8 of Decision 22942-D02-2019 ("the Decision") regarding the application from the Alberta Electric System Operator ("AESO") for approval of the 2018 Independent System Operator ("ISO") Tariff in Proceeding 22942. This review and variance ("R&V") proceeding concerned findings set out in section 8.1 of the Decision regarding a proposal by AltaLink Management Ltd. for a different treatment of AESO contributions in aid of construction.

The AUC decided to rescind the requirements stated in section 8.1 of the Decision. Section 8.1 required that FortisAlberta Inc. ("Fortis") transfer the unamortized balance of its AESO contributions as at December 31, 2017 to AltaLink Management Limited ("AML") and that the new contribution policy proposed by AML be applied effective January 1, 2018. The decision is based on findings in two main areas.

> (i) The AUC found that if the Decision were confirmed and Fortis was required to transfer the unamortized balance of AESO contributions as at December 31, 2017, to AltaLink, Fortis would incur incremental income tax, carrying costs and debt restructuring costs of at least $116.6 million that would be required to be recovered from ratepayers.
>
> (ii) The AUC found that a majority of the approximately $40 million in savings to ratepayers on which the Hearing Panel relied as the basis for requiring Fortis to transfer the unamortized balance of AESO contributions and to apply the new contribution policy proposed by AltaLink can be achieved by directing Fortis to adjust the applicable amortization rate for its AESO contributions to match the service lives of the transmission assets.

<u>Background</u>

After receiving the request from Fortis to commence an R&V proceeding, the AUC limited the scope of the proceeding to the changes made to the AESO's customer contribution policy that had been approved in Section 8 of the Decision and indicated that the proceeding would focus on the second stage of the two-stage R&V process established according to Rule 016.

As part of its supplemental submission, Fortis requested that the AUC immediately stay Section 8 of the Decision pending the disposition of the R&V proceeding.

In this decision, the members of the AUC panel who authored the original decision were referred to as the "Hearing Panel," and the members of the AUC panel considering the R&V application were referred to as the "Review Panel."

Review Panel's Decision

In section 8.1 of the Decision, the Hearing Panel considered a proposal advanced by AML to change how the AESO's contribution policy is accounted for as between a distribution facility owner ("DFO") (Fortis) and a transmission facility owner ("TFO") (AML). The Hearing Panel found that AML's contribution proposal would result in a $40 million financial benefit to customers during the 2018-2022 performance-based regulation ("PBR") term.

This finding led to two requirements. First, approximately $400 million of unamortized AESO customer contributions in Fortis's rate base (the balance effective December 31, 2017) were to be transferred to AML for which Fortis was to be compensated at net book value ("NBV") (the "rate base transfer"). Second, as of January 1, 2018, the AESO customer contributions would be capitalized by AML, not Fortis (the "AML contribution proposal").

The Review Panel reversed both aspects of the Decision based on the evidence filed in the proceeding that was not available to the Hearing Panel. The Review Panel concluded that the costs to Fortis (that would be recoverable from ratepayers) resulting from the transfer of unamortized customer contributions from Fortis to AML significantly outweigh the financial benefits that would occur during the 2018-2022 period. The Review Panel also set aside the commencement of the AML contribution proposal on January 1, 2018.

The Review Panel rescinded the Hearing Panel's determination that ratepayers would derive a material benefit valued at approximately $40 million from the adoption of the AML contribution proposal. The Hearing Panel's finding of benefit was based on the effect of applying AML's lower cost of debt and lower depreciation rates to the balance of Fortis' unamortized customer contributions as at December 31, 2017, over the 2018-2022 period. The Review Panel found that a significant majority of the $40 million could be offset by requiring Fortis to adjust its depreciation rate to match the rate that AML would utilize on the unamortized balance of customer contributions as at January 1, 2018. The income tax, carrying costs and debt restructuring costs that the Review Panel determined would arise would require Fortis to recover incremental costs of at least $ 111 million from ratepayers. This would be in addition to offsetting a portion of the $ 40 million benefit that would arise from the adoption of the AML contribution proposal by requiring Fortis to adjust its depreciation rate.

The Review Panel also considered two categories of additional benefits advanced by AML. These were related to the method of calculation of the NBV of Fortis' unamortized AESO contributions, and to AML's forecast of savings that would be realized by Fortis ratepayers from the replacement of Fortis' projected K-bar amounts with the actual and forecast cost of energized projects. The Review Panel did not accept either of these purported savings as benefits to ratepayers over the 2018-2022 period.

Regarding Fortis's submissions that the Hearing Panel's decision in Section 8 of the Decision was legally unsound, the Review Panel noted that it based its decision on the conclusion that the costs to ratepayers outweighed the benefits. Further, the decision was based on the conclusion, that Fortis could achieve the majority of the $40 million benefit by adjusting its depreciation rate of the unamortized balance of customer contributions to match the service lives of the transmission assets. The Review Panel noted that it did not base its decision on any legal argument advanced by Fortis and found it unnecessary to consider the legal arguments in this decision.

The Review Panel decided to rescind the Decision in respect of the implementation of the AML contribution proposal and the transfer of rate base associated with the unamortized AESO contributions from Fortis to AML.

The Review Panel decided to set aside the commencement of any new customer contribution policy on January 1, 2018. The AUC scheduled a separate proceeding, that will focus on the legal basis of the current AESO customer contribution policy as it pertains to all transmission facility owners ("TFOs") and distribution facility owners ("DFOs"). It will further consider whether the need for a new policy including considerations of AML's contribution proposal. If approved, the AUC will set the date on which any new policy would commence. If a new policy was approved, the commencement date would be on a prospective basis and all DFOs and TFOs, the AESO and other interested parties would be expected to participate.

***ENMAX Energy Application for True-Up of the 2017-2020 Regulated Rate Option Interim Rates,* AUC Decision 25881-D01-2020**

Rates - Regulate Rate Option

In this decision, the AUC approved the application from ENMAX Energy Corporation ("EEC") to true-up its 2017-2020 regulated rate option ("RRO") non-energy interim rates. EEC further applied to true-up its 2015-2016 RRO non-energy tariff final rates rider.

Introduction and Background

EEC filed this application pursuant to AUC directions from decisions 21646-D01-2016 and 21646-D02-2020. These decisions approved EEC's 2016 final rates and its 2017 interim rates, effective January 1, 2017, until July 31, 2020. Decision 21646-D02-2016 also included approval of a rate rider to refund the difference between EEC's approved interim and final rates for January 2015 to October 2016.

This application aimed to true-up the difference between EEC's revenues from January 1, 2017, to July 31, 2020. This true-up was to be based on the interim rates, and the revenues EEC would have collected during the same period if it had been using the approved final rates.

EEC calculated the differences between its revenues using interim rates and final approved rates, from January 1, 2017, to July 31, 2020. EEC also filed information showing the differences between the true-up amount refunded to customer sites and the amount that was approved for refund on a forecast basis, through the 2015-2016 rider.

EEC proposed to collect or refund the true-up over the period from January 1, 2021, to June 30, 2021, as a rate rider that would be included as part of its RRO non-energy tariff. It proposed to collect $0.0040 per day per site through a residential service rate rider and to refund $0.1170 per day per site through a commercial service rate rider, from January 1, 2021 to June 30, 2021.

AUC Findings

The AUC found that EEC correctly calculated the true-up amounts for the RRO non-energy tariff and approved the amounts as submitted by EEC. The AUC approved the collection and refund of the true-up amount over one month as the true-up amounts per customer were relatively small, and this would result in regulatory efficiency. The AUC approved the rider period of December 1, 2020, to December 31, 2020, and the associated rider amounts as a collection of $0.7192 per residential site in December and a refund of $21.11 for commercial sites.

***ENMAX Power Corporation 2019 Annual Transmission Access Charge Deferral Account True-Up*, AUC Decision 25778-D01-2020**

Rates - Deferral Accounts

In this decision, the AUC approved the application from ENMAX Power Corporation ("EPC") for its 2019 annual transmission access charge deferral account ("TACDA") true-up and carrying costs on the true-up amounts following Rule 023: *Rules Respecting Payment of Interest*. The AUC approved the collection of the 2019 TACDA true-up amount of $19.913 million through a transmission access charge rider.

Introduction and Background

EPC applied for the net 2019 TACDA true-up collection of $19.913 million from customers. Under the provisions of the performance-based regulation ("PBR") framework approved in Decision 2012-237, and subsequently adopted for the 2018-2022 PBR term in Decision 20414-D01-2016 (Errata), EPC's TACDA is a dollar-for-dollar flow-through of the Alberta Electric System Operator ("AESO") tariff charges.

2019 TACDA True-Up Amount

The total applied for true-up amount of $19.91 million included the following components:

Component	True-up Amount Collection/(Refund) ($ million)	Methodology to Attribute the True-Up amount to Rate Classes
Previous deferral account rider true-up	0.38	Determined as the difference between the amount approved for collection or refund by rate class and the amount actually collected or refunded for each rate class.
2019 system access service (“SAS”) deferral true-up	(25.82)	AESO costs were allocated to rate classes using EPC’s Phase II cost-of-service methodology underlying its SAS rates.
AESO deferral account reconciliation (“DAR”) true-up	6.85	Allocated to the rate classes in proportion to the actual 2019 energy consumed by rate class.
2019 Balancing Pool true-up	0.03	Allocated to rate in proportion to the actual 2019 energy consumption by rate class.
Carrying costs	(1.35)	Allocated to the rate classes in proportion to their deferral balances (for which carrying costs have been assessed) allocated to them in the preceding components of this true-up calculation.
Total collect/(refund)	**(19.91)**	**Calculated as the sum of all items.**

AUC Findings

The AUC found the application and schedules to have been consistent with the harmonized framework approved by the AUC in Decision 3334-D01-2015 and that the amounts composing the 2019 annual TACDA true-up were reasonable. The AUC further found EPC’s assignment of the individual components to rate classes to have been reasonable in the circumstances and consistent with previously approved methodologies. The AUC approved the net collection of $19.913 million by EPC.

As previously directed by the AUC, EPC calculated carrying costs based on the weighted average Bank of Canada monthly bank rate in months in which the interest rate changed. The AUC directed EPC to continue this method in its next TACDA true-up application.

The AUC found that AESO DAR amounts should not be included in the calculation and allocation of carrying costs if there are no carrying costs assessed on the AESO DAR amounts. EPC was accordingly directed to exclude the AESO DAR amounts from the calculation and allocation of carrying costs in future TACDA true-up proceedings where carrying costs would not be assessed on the AESO DAR.

Rider Implementation Period and Customer Bill Impacts

EPC proposed that its 2019 annual TACDA true-up transmission access charge (“TAC”) rider be in effect from January 1, 2021, to December 31, 2021.

The AUC reviewed the total bill impacts of the proposed TAC rider and noted that rate shock would be unlikely, as the bill changes were below the 10 per cent threshold, which had previously been used as an indicator of rate shock.

TAC Rider Rate

The TAC rider would be affected by the total true-up amount, related carrying costs, and the implementation period of the rider.

The AUC accepted EPC's proposal to calculate the TAC rider using the 2021 forecast billing determinants. The AUC noted that, in making this determination, it had been mindful that the 2019 TAC rider would eventually be trued up to ensure the approved amounts were collected from, or refunded to, customers. The AUC approved EPC's TAC rider per rate class, as suggested by EPC effective January 1, 2021.

Combining Annual TACDA Applications with the Annual PBR Rate Adjustment Filings

The AUC directed EPC to include its 2020 TACDA true-up application and supporting materials as part of its 2022 annual PBR rate adjustment filing. As part of that proceeding, the AUC would evaluate the effectiveness of such an approach to reduce the administrative burden and enhance regulatory efficiency and would, based on its review, consider adopting it for all future TACDA applications.

***EPCOR Distribution & Transmission 2019 Annual Transmission Access Charge Deferral Account True-Up*, AUC Decision 25803-D01-2020**
Rates - Deferral Accounts

In this decision, the AUC approved the application from EPCOR Distribution & Transmission Inc ("EPCOR") for its 2019 annual transmission access charge deferral account ("TACDA") true-up and carrying costs on the true-up amounts following Rule 023: *Rules Respecting Payment of Interest*. The AUC approved the collection of the 2019 TACDA true-up amount of $3.82 million through a Rider J, effective January 1, 2021.

Introduction and Background

EPCOR applied for the net 2019 TACDA true-up collection of $3.82 million from customers. Under the provisions of the performance-based regulation ("PBR") framework approved in Decision 2012-237, and subsequently adopted for the 2018-2022 PBR term in Decision 20414-D01-2016 (Errata), EPCOR's TACDA is a dollar-for-dollar flow-through of the Alberta Electric System Operator ("AESO") tariff charges.

2019 TACDA True-Up Amount and Rider J Rate

The total applied for true-up amount of $3.82 million included the following components:

Component	**True-up Amount Collection/(Refund) ($ million)**	**Methodology to Attribute the True-Up amount to Rate Classes**
Previous deferral account rider true-up	0.01	Determined as the difference between the amount approved for collection or refund by rate class and the amount actually collected or refunded for each rate class.
2019 system access service ("SAS") deferral true-up	(1.16)	AESO costs were allocated to rate classes using EPCOR's Phase II cost-of-service methodology. underlying its SAS rates, except for transmission direct-connect customers. Since transmission direct-connect customers were billed on a flow-through basis, no amounts were allocated to this customer class.
AESO deferral account reconciliation ("DAR") true-up	5.03	Allocated to the rate classes in proportion to the actual 2019 energy consumed by rate class.
2019 Balancing Pool true-up	(0.04)	Allocated to rate in proportion to the actual 2019 energy consumption by rate class.
Carrying costs	(0.07)	Allocated to the rate classes in proportion to their deferral balances (for which carrying costs have

		been assessed) allocated to them in the preceding components of this true-up calculation.
Total collect/(refund)	**(3.82)**	**Calculated as the sum of all items.**

AUC Findings

The AUC found the application and schedules to have been consistent with the harmonized framework approved by the AUC in Decision 3334-D01-2015 and that the amounts composing the 2019 annual TACDA true-up were reasonable. The AUC further found EPCOR's assignment of the individual components to rate classes to have been reasonable in the circumstances and consistent with previously approved methodologies. The AUC approved the net collection of $3.82 million by EPCOR.

As previously directed by the AUC, EPCOR calculated carrying costs based on the weighted average Bank of Canada monthly bank rate in months in which the interest rate changed. The AUC directed EPCOR to continue this method in its next TACDA true-up application.

The AUC found it unreasonable to include AESO DAR amounts in the calculation and allocation of carrying costs when there are no carrying costs assessed on the AESO DAR amounts. EPCOR was accordingly directed to exclude the AESO DAR amounts from the calculation and allocation of carrying costs in future TACDA true-up proceedings where carrying costs would not be assessed on the AESO DAR.

Rider Implementation Period and Customer Bill Impacts

EPCOR proposed that its 2019 annual TACDA true-up Rider J be in effect from January 1, 2021, to December 31, 2021. The AUC reviewed the total bill impacts of the proposed Rider J and noted that rate shock would be unlikely, as the bill changes were below the 10 per cent threshold, which had previously been used as an indicator of rate shock.

Rider J Rate

Rider J Rates would be affected by the total true-up amount, related carrying costs, and the implementation period of the rider. The AUC accepted EPCOR's proposal to calculate the Rider J Rate using the 2021 forecast billing determinants. The AUC noted that, in making this determination, it had been mindful that the 2019 rider would eventually be trued up to ensure the approved amounts were collected from, or refunded to, customers. The AUC approved EPCOR's Rider J per rate class, as suggested by EPCOR, effective January 1, 2021.

Combining Annual TACDA Applications with the Annual PBR Rate Adjustment Filings

The AUC directed EPCOR to include its 2020 TACDA true-up application and supporting materials as part of its 2022 annual PBR rate adjustment filing. As part of that proceeding, the AUC would evaluate the effectiveness of such an approach to reduce the administrative burden and enhance regulatory efficiency and would, based on its review, consider adopting it for all future TACDA applications.

***FortisAlberta 2019 Annual Transmission Access Charge Deferral Account True-Up*, AUC Decision 25801-D01-2020**

Rates - Deferral Accounts

In this decision, the AUC approved the application from FortisAlberta Inc. ("Fortis") for its 2019 annual transmission access charge deferral account ("TACDA") true-up and carrying costs on the true-up amounts following Rule 023: *Rules Respecting Payment of Interest.* The AUC approved the collection of the 2019 TACDA true-up amount of $34.576 million through a base 2021 transmission adjustment rider ("TAR").

Introduction and Background

Fortis applied for a net 2019 TACDA collection of $34.576 million from customers. Under the provisions of the performance-based regulation ("PBR") framework approved in Decision 2012-237, and subsequently adopted for the 2018-2022 PBR term in Decision 20414-D01-2016 (Errata), Fortis's TACDA was a dollar-for-dollar flow-through of the Alberta Electric System Operator ("AESO") tariff charges.

2019 TACDA True-Up Amount

The total applied for true-up amount of $34.576 million included the following components:

Component	**True-up Amount Collection/(Refund) ($ million)**	**Methodology to Attribute the True-Up amount to Rate Classes**
Previous deferral account rider true-up	1.73	Determined as the difference between the amount approved for collection or refund by rate class and the amount collected or refunded for each rate class.
2019 system access service (SAS) deferral true-up	(24.58)	AESO costs were allocated to rate classes (excluding transmission connected) using Fortis's Phase II cost-of-service methodology underlying its SAS rates. The SAS true-up also included amounts related to Option M
AESO deferral account reconciliation (DAR) true-up	57.58	Allocated to the rate classes (excluding transmission connected) in proportion to the actual 2019 energy consumed by rate class.
2019 Balancing Pool true-up	(0.68)	Allocated to rate classes (excluding transmission connected) in proportion to the actual 2019 energy consumption by rate class.
Border customer deferral	0.29	Extra-provincial suppliers that serve border customers in FortisAlberta service area include Marias River Electric Cooperative, SaskPower, and Hill County Electric Co-op. Border customer amounts were allocated based on all recorded energy. Included transmission connected customers.
Carrying costs	0.24	Allocated to the rate classes in proportion to their deferral balances (for which carrying costs have been assessed) allocated to them in the preceding components of this true-up calculation.
Total collect/(refund)	**34.58**	**Calculated as the sum of all items.**

AUC Findings

The AUC found the application and schedules to have been consistent with the harmonized framework approved by the AUC in Decision 3334-D01-2015 and that the amounts composing the 2019 annual TACDA true-up were reasonable. The AUC further found Fortis's assignment of the individual components to rate classes to have been reasonable in the circumstances and consistent with previously approved methodologies. The AUC approved the net collection of $34.576 million by Fortis.

The AUC directed Fortis, for its next TACDA true-up application, to continue to calculate carrying costs based on the weighted average Bank of Canada monthly bank rate in months in which the interest rate changed.

The AUC found that AESO DAR amounts should not be included in the calculation and allocation of carrying costs if there are no carrying costs assessed on the AESO DAR amounts. Fortis was accordingly directed to exclude the AESO DAR amounts from the calculation and allocation of carrying costs in future TACDA true-up proceedings where carrying costs would not be assessed on the AESO DAR.

Rider Rate, Implementation Period and Customer Bill Impacts

Fortis proposed that its 2019 annual TACDA true-up TAR be in effect from January 1, 2021, to December 31, 2021. Fortis proposed to implement its 2021 TAR as a percentage of the base transmission access charges component of its distribution tariff.

AUC Findings

The AUC approved the 2019 annual TACDA true-up TAR to be in effect on January 1, 2021. The TAR percentage rate and any required rate mitigation would be determined in Fortis' 2021 annual PBR rate adjustment filing in proceeding 25843.

Combining Annual TACDA Applications with the Annual PBR Rate Adjustment Filings

The AUC directed Fortis to include its 2020 TACDA true-up application and supporting materials as part of its 2022 annual PBR rate adjustment filing. As part of that proceeding, the AUC would evaluate the effectiveness of such an approach to reduce the administrative burden and enhance regulatory efficiency and would, based on its review, consider adopting it for all future TACDA applications.

Sage Water Services Interim Water Rates, **AUC Decision 24797-D01-2020**

Retroactive Ratemaking - Exception

In this decision, the AUC approved the existing water services rates of Sage Water Services Corp. ("Sage Water"), as interim rates, effective November 19, 2020.

Introduction and Background

On June 28, 2019, the AUC received an application from Sage Water requesting approval for final water rates. Sage Water indicated that it operates an investor-owned potable water utility with a small customer base. Sage Water had not previously applied for or received Commission approval of water rates charged to its customers. Sage Water subsequently filed a second application on July 31, 2019, requesting approval of interim water rates effective July 1, 2019. In both applications, Sage Water proposed to change the rate structure from a flat monthly fee to one that is based on a combination of a fixed fee and a variable fee based on consumption. On August 21, 2020, Sage Water filed a revised application with the AUC for approval of interim water rates effective July 1, 2019, through March 31, 2023.

On October 16, 2020, the AUC issued a ruling that Sage Water is an "owner of a public utility" for purposes of the *Public Utilities Act* and subject to the authority of the Commission.

Sage Water provides water service to the Prince of Peace Lutheran School, the Prince of Peace Harbour, the Prince of Peace Manor and the Prince of Peace Condominium Village (the "Village"), located in Rocky View County ("RVC"), on the east side of Calgary, Alberta.

Interim Water Rates and Effective Date

Sage Water submitted that it had been operating at a loss since July 1, 2019, and that operating losses and subsequent operating cash shortfalls were wholly covered by Sage Properties.

Sage Water proposed the interim water rates proposed to reduce the operating losses provisionally until a water line to connect the area to the RVC water reservoir located in Conrich, Alberta, could be constructed and an agreement could be reached with RVC to bill customers directly for water. Sage Water expects the water line to be constructed by December 2021 or earlier.

Effective Date

The AUC noted the rule against retroactive ratemaking. Utility regulators cannot retroactively change, or substitute a rate previously charged. Courts have found limited exceptions to the rule against retroactive ratemaking, namely: interim rate orders, deferral accounts, null decisions, knowledge and misconduct. The AUC noted that with the possible exception of knowledge, none of those circumstances are present here.

The knowledge exception to the rule against retroactive ratemaking applies where the parties that would be subject to a rate that would otherwise be considered a retroactive rate, had knowledge that the rate may change. The notice of application for Sage Water's interim rates proceeding was issued on September 24, 2020. The AUC stated that this was the earliest date that Sage Water's ratepayers arguably had knowledge that Sage Water's rates may be subject to change. However, this date preceded October 16, 2020, the date on which the AUC confirmed that Sage Water is a public utility subject to the jurisdiction of the AUC. Given the short period between October 16, 2020, (the date by which there was both notice and jurisdiction), and the date on which this decision was issued, the AUC considered it reasonable that Sage Water's interim water rates will come into effect on November 19, 2020. Sage Water was directed to apply the approved interim rates effective that date.

Solar Krafte Utilities, Capital Power Generation Services Strathmore Solar Project, **AUC Decision 25346-D01-2020**

Facilities - Solar Generation

In this decision, the AUC approved an application from Solar Krafte Utilities Inc. ("Solar Krafte") to construct and operate a power plant designated as the Strathmore Solar Project, and to connect the proposed power plant to the Alberta Interconnected Electric System (collectively, "the Project").

<u>Application Details</u>

The Project will have a total generating capability of 40.5 MW and will connect to Fortis' distribution system via AltaLink Management Ltd.'s Strathmore 151S Substation, located directly north of the project boundary. Solar Krafte included in its application a participant involvement program ("PIP"), a noise impact assessment ("NIA"), a solar glare hazard analysis report, an environmental protection plan ("EPP") including mitigations, and a letter from Alberta Environment and Parks ("AEP") Wildlife Management.

<u>Sur-Reply Argument - Procedural Issues</u>

Cyber Investments Ltd. ("Cyber") opposed the project and argued that Solar Krafte had deliberately split its case in argument to deny Cyber the opportunity to respond to material aspects of its case. The AUC acknowledged that Solar Krafte introduced new evidence in its reply argument. The AUC noted it did not support this practice as it could lead to procedural unfairness. However, the AUC found that any prejudice associated with the introduction of the new evidence was largely mitigated by the filing of Cyber's sur-reply.

<u>Material Issues</u>

Inclusion of Capital Power and Procedural Fairness

Despite a request from Cyber, the AUC did not incorporate additional process steps to reflect the conditional sale of the project by Solar Krafte to Capital Power. The AUC did provide Cyber the opportunity to file a submission that detailed its concerns with Capital Power being added as an applicant. Regarding procedural fairness, Cyber raised concerns regarding its inability to ask information requests of Solar Krafte and Capital Power.

The AUC was not persuaded that the addition of Capital Power as an applicant changed the project scope or the facilities approvals being requested. In the AUC's view, Cyber failed to demonstrate that the decision to add Capital Power as an applicant and proceed with its consideration of the project without allowing further information requests prejudiced Cyber's participation in the proceeding.

Consultation

The AUC found that Solar Krafte's consultation methods had presented opportunities for potentially affected stakeholders, including Cyber, to understand the nature of the application. Further, the information requests Cyber asked of Solar Krafte were focused on Cyber's areas of concern and were issued by Cyber's legal counsel. The AUC considered that Cyber was able to understand the nature of the application enough to identify its specific areas of concern. While Solar Krafte was ultimately unable to address or resolve Cyber's concerns, the AUC was satisfied that Solar Krafte's participant involvement program achieved the purpose of consultation.

Municipal Land Development

Cyber purchased its lands adjacent to the project lands in 2005. Cyber submitted that it intended to develop its lands as a mixed-use development with both residential and commercial components, which it had called the Legacy Creek Development Concept ("Legacy Creek").

The lands the Strathmore Solar Project would be sited on are owned by the Town of Strathmore (the "Town"). In March 2018, Solar Krafte and the Town agreed to a long-term lease for the lands, with the intent of Solar Krafte to develop a solar farm on the lands. The Town's current municipal development plan (MDP-2014) showed a mix of highway commercial, residential, and industrial land uses for the subject lands. Under the current land use bylaw ("LUB"), the existing land use in the area was a mix of designations.

Cyber raised concerns that the proposed project would be inconsistent with the MDP-2014 and that construction of the project would impact its ability to develop its proposed Legacy Creek development.

The AUC took note of Cyber's correspondences with the Town which stated that Cyber, a private landowner, could have applied to the Town to amend the current zoning of its lands to allow for it to proceed with its Legacy Creek development, as doing to would be in line with the MDP-2014. The AUC was not convinced that the prospect of a future zoning amendment would negate the uses of the Town's land as designated.

The AUC found that the Project was consistent with the existing land use zoning bylaws and is supported by the Town.

AUC Findings on Development Impacts

The AUC noted that Section 619 of the *Municipal Government Act* provides guidance on how to resolve conflicts between municipal approvals and those issued by various provincial regulators including the AUC. Section 619 states:

> 619(1) A licence, permit, approval or other authorization granted by the NRCB, ERCB, AER, AEUB or AUC prevails, in accordance with this section, over any statutory plan, land use bylaw, subdivision decision or development decision by a subdivision authority, development authority, subdivision and development appeal board, or the Municipal Government Board or any other authorization under this Part.

The AUC stated that section 619 recognizes the need for consistent regulation of utility facility projects, including power plants, across the province. While the provision provides that an approval of the AUC will prevail over a conflicting municipal planning instrument, it does not prohibit, or otherwise prevent, the AUC from having regard for such instruments when deciding on an application.

The AUC disagreed with Cyber's contention that considering a project's compliance, or non-compliance, with municipal planning requirements results in improper sub-delegation. Rather, consideration of whether a project complies with municipal planning instruments is one of a number of factors that the AUC may consider, on a case by case basis, when assessing whether approval of a project is in the public interest. However, the AUC is not obliged to question or consider the adequacy of the Town’s municipal development application process or how it considered the Project when it approved the development permit.

Property Valuation

Cyber raised concerns that the Project would negatively affect the value of its lands. The AUC found the property value evidence relied upon by Cyber was of limited value because it had been predicated on an uncertain development scenario. The property value estimated relied upon was premised upon several contingent events not under Cyber’s control.

Given the speculative nature of Cyber’s Legacy Creek development, the AUC was not persuaded to consider Cyber‘s future development plans when assessing valuation impacts. Therefore, the AUC was not convinced that it should deny the application based on a potential impact on the future value of Cyber’s lands.

<u>Additional Issues</u>

Irrigation

Regarding irrigation, the AUC noted Cyber’s general concerns regarding its ability to access water from the nearby irrigation system. The AUC further noted the concerns that approval and construction of the Project could result in incremental irrigation costs for Cyber as a result of routing limitations for the irrigation services associated with the Project.

While Cyber had yet to formalize an agreement with Western Irrigation District (“WID“) for irrigation services, the evidence before the AUC was that such an agreement remains possible. The parties were in agreement that there would be an incremental cost if Cyber’s lands would be serviced from water lines along the southern boundary of the Project. The agreement between Solar Krafte and WID would require Solar Krafte to be responsible for these incremental costs. As such, the AUC finds that this agreement would mitigate Cyber’s concerns regarding irrigation water access to an acceptable degree.

Stormwater Runoff and Drainage

Regarding stormwater runoff and drainage concerns raised by Cyber, the AUC acknowledged that the proposed project features could have a potential drainage impact.

Consequently, the AUC imposed a condition on the approval. The condition provided Capital Power with two alternatives but required that Capital Power develop and finalize a site servicing plan and a drainage and stormwater management plan in consultation with the Town before commencing construction.

Emergency Response

Cyber raised concerns that Solar Krafte did not have a finalized site-specific emergency response plan for the Project and had not addressed its fire-related concerns during the consultation. The AUC found no persuasive evidence that the proposed Project would likely result in increased fire risk or an increase in other safety risks for Cyber’s attendees or any other stakeholder in the area. In response to concerns raised by Cyber, the AUC did impose a condition that required Solar Krafte to develop and implement a site-specific emergency response plan for the Project.

Reclamation and Abandonment

Cyber raised concern that any failure by Solar Krafte to reclaim the Project land would have a direct impact on Cyber and its investment in that land.

The AUC noted that there were no requirements or authority for it to require reclamation deposits from power plant approval holders. The AUC considered several factors when assessing potential reclamation liability as part of its overall public interest assessment of a Project.

Solar Kraft committed to meet the AEP *Conservation and Reclamation Directive for Renewable Energy Operations* and to restore the Project site to substantially the same condition as it was at the commencement date of the lease. The AUC accepted these commitments and found they satisfied concerns regarding reclamation.

Solar Glare, Noise and Visual Impact

Cyber raised concerns regarding solar glare, noise, and visual impacts. Regarding noise issues, the AUC relied on the submitted NIA in accepting that the Project would comply with Rule 012. The AUC considered that the noise contribution from the Project would be minor.

Notwithstanding the prediction of zero glare impact, the AUC wanted to ensure that any glare associated with the Project would be addressed by Capital Power in a timely manner. As a result, the AUC imposed further conditions on the approval requiring Capital Power to take specific measures to minimize glare. The conditions further required Capital Power to file a report detailing complaints and concerns it would be made aware of regarding solar glare during the first year of operation.

Concerning visual impacts to Cyber, the AUC stated that it was too early for visual mitigation to be installed, and did not find it necessary to condition its approval on the installation of mitigative landscaping features.

<u>Overall AUC Findings</u>

For the reasons noted, the AUC found that subject to the imposed conditions, the approval of the Project would be in the public interest.

Town of Canmore Water and Wastewater Service Agreement with the Municipal District of Bighorn for the Hamlet of Dead Man's Flat, **AUC Decision 25890-D01-2020**

Rates - Water Services

In this decision, the AUC approved the application from the Town of Canmore ("Canmore") for approval of a potable water and wastewater service agreement between Canmore and the Municipal District of Bighorn ("Bighorn"), for the hamlet of Dead Man's Flats ("Hamlet").

<u>Introduction and Background</u>

The proposed service agreement would be for an initial term of five years, to be renewed automatically, upon AUC approval, for an additional period of approximately 45 years, expiring March 31, 2070.

Canmore stated that the new service agreement was approved by an inter-municipal committee made up of elected officials from both Canmore and Bighorn, and had been executed on April 1, 2020, after being approved by both councils.

The service agreement would establish that utility rates for water services would be determined on a cost of service basis, in accordance with the guiding principles approved by Canmore Council and subject to Section 2 of the *Public Utilities Act*, and the requirement that rates charged or proposed to be charged must be just and reasonable.

As it was outside the AUC's jurisdiction, the AUC noted it would not be making any findings in this decision concerning wastewater.

AUC Findings

Based on its review and considering the approval by the inter-municipal committee and both councils, the AUC found that the water and wastewater service agreement between Canmore and Bighorn was necessary and proper for public convenience and properly conserved the public interest. Accordingly, the AUC approved the water and wastewater service agreement, as filed.

***Windrise Wind Energy Inc. - Transmission Line 497L and Interconnection*, AUC Decision 25074-D02-2020**
Facilities - Transmission Lines

In this decision, the AUC considered whether to approve Application 25074-A002 by Windrise Wind Energy Inc. to construct and operate a 138-kilovolt transmission line from Windrise 1063S Substation to Windy Flats 138S Substation and Application 25074-A004 to connect the line to AltaLink Management Ltd.'s Windy Flats 138S Substation (collectively, the "Proposed Project"). The AUC had previously approved a needs identification document and the alteration of the Windy Flats substation in Decision 2574-D01-2020.

The AUC found that approval of Transmission Line 497L along Alternate Route A and the connection of the line to the Alberta Interconnected Electric System ("AIES") are in the public interest, having regard to the social, economic, and other effects of the applications, including their effect on the environment.

Introduction

The AUC approved the Windrise Wind Power Project in Decision 24699-D01-2019. That project consists of a 206.4-megawatt (MW) wind power plant, collector lines and the Windrise 1063S Substation, all owned and operated by Windrise Wind Energy Inc. (Windrise). Windrise is the general partner of Windrise Wind LP, which is a wholly owned subsidiary of TransAlta Corporation.

Windrise applied to the Commission for approval to construct and operate a 138-kV transmission line designated as Transmission Line 497L from the Windrise 1080S Substation to AltaLink's Windy Flats 138S Substation approximately ten kilometres southwest of the Town of Fort Macleod in the Municipal District of Willow Creek No. 26. Windrise also applied for approval to connect the transmission line to the Alberta Interconnected Electric System. The applications were registered as applications 25074-A002 and 25074-A004 on November 29, 2019.

Windrise submitted a preferred route and two alternate route options for the transmission line. The preferred route was also identified by Windrise as route B and was referred to in the decision as Preferred Route B. The alternate routes were referred to as Alternate Route A and Alternate Route C.

The AUC granted standing to a number of individual interveners, who were landowners living in proximity to at least one of the proposed routes.

Route Selection Process

The AUC found the preferred and alternate routes developed by Windrise were generally compatible with transmission line development, based on the project siting methodology adopted by Windrise, and took into account factors such as: paralleling existing transmission lines, minimizing construction impacts and risks, avoiding construction impediments and minimizing environmental impacts.

Windrise's use of a route metrics table based on the four categories of potential impacts selected by Windrise and its environmental consultants was also reasonable and consistent with guidance provided by Rule 007 and previous Commission decisions. With the exception of some intervenors' concerns about impacts to farmyards, all parties agreed with the choice of factors Windrise considered in its metrics table.

Environmental Impacts

The AUC noted that the environmental evaluation prepared by Windrise's expert concluded that, with sufficient mitigation measures, either Alternate Route A or Preferred Route B would be suitable from an environmental perspective. This conclusion was generally supported by an expert for a group of landowners known as the Route A Support Group (the "RASG"), who noted that the proposed mitigation measures should reduce the impacts of Alternate Route A and Preferred Route B on wetlands, grasslands and associated biodiversity to an acceptable level.

The AUC accepted the environmental evaluation's conclusion that, except for routing in close proximity to McBride Lake, the potential environmental effects of the proposed Project would be "not significant" and found that the environmental effects of the proposed Project could be adequately mitigated, given diligent implementation of the mitigation measures proposed in the environmental evaluation and EPP, and the commitments made by Windrise.

The Commission accepted the evidence of Windrise and the RASG's expert and found that Alternate Route C would have the largest impact on the environment. In addition, the Commission agreed with RASG's expert that the Preferred Route B would have the next largest impact due to the number of easements, wetland infringements and structures located within undeveloped road allowances.

Landowner Impacts

Electromagnetic Fields ("EMF")

In the absence of expert evidence suggesting otherwise, the AUC placed significant weight on the World Health Organization's conclusion that, based on available research data, exposure to EMFs is unlikely to constitute a serious health hazard, and also on Health Canada's conclusion that exposure to EMFs from transmission lines is not a demonstrated cause of any long-term adverse effect to human or animal health. Accordingly, the AUC found that there is no evidence to suggest that EMFs from the transmission line will result in any adverse health effects.

Residential Impacts

The AUC noted that many interveners raised concerns about a variety of potential impacts that they believe the proposed Project would have on their residential properties, including property devaluation, visual impacts and noise. The AUC found that given the lack of expert evidence to demonstrate an adverse impact on property values, the AUC found that the interveners' concerns were not substantiated.

The AUC further found that by locating the transmission line within road allowances and paralleling existing linear disturbances, the residential impacts associated with the proposed routes would be considerably mitigated and it does not expect residential impacts to be significant.

Lastly, with respect to noise, the AUC accepted Windrise's evidence that the transmission line will not be a significant source of audible noise and was satisfied with Windrise's commitments to comply with the requirements of Rule 012 and with applicable bylaws as those pertain to construction noise.

Traffic Safety

The AUC found that there was a low risk to traffic safety and the impacts will be temporary.

Agricultural Impacts

The AUC found that Windrise's practices and procedures to reduce the spread of soil-borne diseases and noxious weeds were reasonable. Regarding electrical effects from the transmission line, the AUC noted that Windrise committed to conducting pre-construction EMF measurements for stakeholders who raise concerns in relation to radio interference, and would also work with stakeholders post-construction to mitigate EMF interference caused by its facilities. Windrise also committed to grounding fences, as required, while it operates the transmission line. More generally, the AUC considered the practices that Windrise committed to implement to mitigate agricultural impacts, as well as its commitment to working with landowners throughout the construction of the proposed project.

The AUC found that the commitments made by Windrise were reasonable and that there was no need to impose the additional conditions proposed by intervenors related to agricultural impacts.

Route Selection

The AUC reviewed the submissions of each party regarding the relative advantages and disadvantages of the three proposed route options, and weighed the respective social, economic, and environmental impacts of the routes. The AUC decided to grant approval to Alternate Route A.

Having determined that any health, noise and electrical effects do not support one route over the others, the Commission considered the environmental, residential and agricultural impacts of each of the preferred and alternate routes and found that Alternate Route A has the lowest overall impacts.

CANADA ENERGY REGULATOR

Nova Gas Transmission Ltd. Application to Construct and Operate the Edson Mainline Expansion Project, CER Report GH-001-2019

Pipeline Facilities

In this Report, the CER discussed its recommendation, decisions, and reasons in respect of the application from NOVA Gas Transmissions Ltd. ("NGTL") to construct and operate the Edson Mainline Expansion Project (the "Project"). The Project consisted of "Section 52 Pipeline and Related Facilities", which is the proposed construction and operation of approximately 85 kilometres of new gas pipeline and associated facilities in Alberta. The Project also consisted of "Section 58 Facilities and Activities", which is the proposed Right of Way preparation activities and commencement of trenchless crossings in proposed select locations, the temporary infrastructure required for pipeline construction, and the installation of tie-in assemblies located within the boundaries of the existing NGTL Clearwater Compressor Station.

<u>Recommendation to Governor in Council</u>

As required by section 36 of the transitional provisions for the *Canadian Energy Regulator Act* ("*CER Act*"), the consideration of this application from NGTL by the CER was done according to the *National Energy Board Act* ("*NEB Act*").

Section 52 of the *NEB Act* required that a recommendation be made to the Minister responsible for the Act (the Minister of Natural Resources Canada) as to whether a Certificate of Public Convenience and Necessity ("Certificate") should be issued for any portion of the applied-for pipeline. This decision on the issuance of a Certificate would be required to consider whether the pipeline was and would be required by the present and future public convenience and necessity, and the reasons for that recommendation. Section 52 of the *NEB Act* also required that regardless of the recommendation, the CER must include all the terms and conditions necessary or desirable in the public interest to which the Certificate will be subject if the Governor in Council ("GIC") were to direct the issuance of the Certificate.

Public Convenience and Necessity

In the CER's view, the benefits of the Project were considerable and would be realized throughout the lifecycle of the Project. Project benefits included:

- maintaining access to natural gas supplies for diverse Canadian consumers;
- increased access to intra-basin markets for Canadian natural gas;
- increased training and employment opportunities for Indigenous peoples and potential contracts for Indigenous-owned businesses;
- socio-economic benefits related to the construction phase of the Project, through direct, indirect, and induced employment, as well as contract and procurement opportunities for local communities and workers from elsewhere in Alberta;
- efficient use of and expansion to the NGTL System in terms of Project land requirements; and
- contributions to local, regional, provincial and federal economies.

The CER noted its view that the Project carried burdens which included:

- potential negative effects on the health and well-being of Indigenous peoples and Project workers;

- limitations on access for traditional users within the Project area during active construction and during operations and maintenance activities, as well as corresponding potential socio-economic impacts to Indigenous peoples;

- potential impacts on unidentified traditional land and resource use and cultural sites;

- cultural implications stemming from potential cumulative effects on traditional land and resource use and potential negative impacts on the ability of Indigenous peoples to pass on intergenerational knowledge; and

- permanent loss of 2.4 ha of old seral stage forest, including culturally important plants.

The CER noted its view that, while having respected all considerations directly related and relevant to the application, the Project was and would be required by the present and future public convenience and necessity. In coming to this recommendation, the CER considered the public interest, recognizing that consideration of economic, environmental, and social interests was required.

Environmental Assessment

Subsections 52(3) and 58(6) of the *NEB Act* require that if an application relates to a designated project as defined in section 2 of the *Canadian Environmental Assessment Act, 2012* ("*CEAA 2012"*), the Report concerning the application must also set out an environmental assessment prepared under *CEAA 2012* in respect of the project.

Following this assessment, the CER concluded that the Project was not likely to cause significant adverse environmental effects. This was based on the implementation of NGTL's environmental protection procedures and mitigation measures and the conditions that the CER had recommended and imposed concerning the Section 52 Pipeline and Related Facilities and Section 58 Facilities and Activities respectively.

Consultation with Indigenous Peoples

The CER assessed all evidence on the record, including Indigenous knowledge that had been provided in confidence, and considered NGTL's engagement commitments. Following this assessment and further considering the conditions outlined in this Report, the CER was of the view that the honor of the Crown had been upheld. There had been adequate consultation and accommodation for the CER's recommendation on this Project under section 52 of the *NEB Act* and its decisions under section 58 and Part IV of the *NEB Act*. The CER was also of the view that, within this Project area, any potential Project impacts on the rights and interests of affected Indigenous peoples were not likely to be significant with the implementation of the mitigation measures and commitments made by NGTL, as well as the conditions and accommodations recommended and imposed by the CER.

<u>Decisions Made by the CER</u>

Section 58 Facilities and Activities

NGTL sought exemptions for various facilities and activities from the detailed route process according to section 58 of the *NEB Act*. It stated these exemptions would be required to achieve the proposed construction schedule and commercially required in-service date for the Project. NGTL sought this exemption for temporary infrastructure required for construction of the pipeline, right of way ("ROW") preparation activities, and commencing trenchless crossing in select areas (combined not exceeding 40 km in length). It further requested the exemption for the installation of tie-in assemblies located within the boundaries of the existing Clearwater Compressor Station.

The CER was of the view that the Section 58 Facilities and Activities would be in the public interest, should the Governor in Council direct the Commission to issue a Certificate in respect of the Section 52 Pipeline and Related

Facilities. Accordingly, the Commission made an order pursuant to section 58 of the *NEB Act* exempting NGTL from paragraphs 31(c) and 31(d), and section 33 of the *NEB Act* for the Section 58 Facilities and Activities, subject to conditions outlined in the Report.

Tolling Matters

The CER found NGTL's proposal to roll in the cost of the Project facilities to the rate base for the NGTL System and to apply the existing NGTL System toll methodology to be appropriate.

Conclusion

When considering the balance between the benefits and the burdens associated with the Project, the CER found that the Project is in the public interest and is consistent with the requirements of the *NEB Act*. In assessing NGTL's application, the CER recommended and included conditions in addition to the legislation and standards regarding pipeline integrity, safety, and environmental protection to which the Project would also be subject. In the case of the approval and completion of the Project, NGTL's Accountable Officer would be required to submit a condition compliance filing to the CER for the Section 52 Pipeline and Related Facilities and the Section 58 Facilities and Activities.

Trans Mountain Pipeline ULC Trans Mountain Expansion Project Detailed Route Hearing MH-018-2020, CER Letter Decision

Pipelines - Route Hearing

In this decision, the CER found that the detailed route proposed by Trans Mountain Pipeline ULC ("Trans Mountain") for the Trans Mountain Expansion Project ("TMEP") would be the best possible detailed route on the Lands. The CER found Trans Mountain's proposed timing and method of construction was the most appropriate.

Overview of the Proposed TMEP Pipeline on the Subject Lands.

The scope of Detailed Route Hearing MH-018-2020 was limited to the land owned by the Grays, (the "Lands"). The Grays proposed an alternative to the route proposed by Trans Mountain.

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

Trans Mountain proposed to install the TMEP pipeline within the existing Trans Mountain Pipeline ("TMPL") right of way ("ROW") for the entirety of the route through the Lands. The CER found that Trans Mountain's proposed route is, on a balance of probabilities, the best possible detailed route.

Did Trans Mountain Apply Its Routing Criteria Appropriately?

The Governor in Council ("GIC") approved the criteria recommended by the CER's predecessor, the NEB, to determine the pipeline's route.

Mr. Gray raised concerns that the proposed route (i) was not appropriate for the current community, (ii) would go through a wet area, and (iii) its associated workspace would result in the removal of trees on the Lands. The CER found that the first and third concerns were not about whether the proposed route was practicable. The concern about the wet area was about practicability; however, Trans Mountain's evidence showed that it had plans in place to mitigate potential impacts to wetlands if any were discovered during construction.

The CER found that Trans Mountain had appropriately applied its routing criteria when selecting the proposed route.

Considering the Grays' Proposed Alternate Route, Is Trans Mountain's Proposed Route the Best Possible Detailed Route?

Mr. Gray proposes an alternate route about 60 meters south of the Lands, across a turf farm. This proposed alternate route through adjacent lands would still have been within the approved corridor.

When considering an alternate route, the CER was mindful that Trans Mountain retains the onus to establish, on the balance of probabilities, that its proposed route is the best possible route. One way for a landowner to cast doubt as to whether the proposed route is the best possible route is to propose an alternate route that may be better. However, in considering the proposed alternate route, the CER was not persuaded that Trans Mountain's proposed route is not the best route, on a balance of probabilities.

Mr. Gray's alternate route did not follow the TMPL easement or another existing easement or ROW. It would have required a new easement, which would be located on his neighbours' adjacent properties to the west and south, as well as on the property to the southeast of the Lands. His argument that it would avoid the wet area on the Lands would be related to the feasibility of co-location with the TMPL. However, the CER had found that Trans Mountain's proposed mitigation actions were adequate, such that the proposed route is feasible. Trans Mountain submitted that the TMEP pipeline will cross the watercourse either on the Lands or on the property adjacent to the Lands. The evidence showed no difference in environmental impacts or impacts to Trans Mountain's ability to construct the pipeline according to the specific crossing location. Accordingly, in the CER's view, Trans Mountain's proposed route continued to be the best possible route.

The CER was not persuaded by Mr. Gray's argument that the alternate route avoids trees and vegetation and goes through unhindered land. The evidence demonstrated that Trans Mountain's proposed route also avoided trees and vegetation since it would follow the TMPL easement, which Mr. Gray stated that he kept clear of vegetation. The CER did not agree that the turf farm, that the alternate route would cross, was "unhindered land." According to the evidence, it is cultivated, possibly irrigated, and likely has commercial value. In contrast, the proposed route follows the TMPL easement, which is already encumbered with another pipeline. The CER found it preferable to avoid encumbering additional land with new pipeline easements.

The CER found that Trans Mountain's proposed route reflected an appropriate application of Trans Mountain's routing criteria. The CER found this was not the case with Mr. Gray's alternative route. Therefore, and because Trans Mountain has appropriate plans in place to mitigate any potential impacts to wetlands in the event any are discovered during construction, the CER found, on a balance of probabilities, that Trans Mountain's proposed route was the best possible detailed route.

<u>Are Trans Mountain's Proposed Methods of Construction the Most Appropriate?</u>

Trans Mountain proposed to use only the conventional footprint or open-cut pipeline construction method on the Lands.

In the CER's view, Trans Mountain's criteria to determine its proposed methods of construction on particular lands are reasonable and appropriate. They minimized the risk of failure, prioritize safety, and consider physical constraints both on the surface of the land and subsurface. Further, temporary workspaces would be located to avoid proximity to residences, treed areas, and areas of environmental or cultural sensitivity. Where a landowner raises concerns, the CER was of the view that the criteria were flexible enough to allow Trans Mountain to incorporate mitigation strategies in response. The CER concluded that Trans Mountain's proposed method was, on a balance of probabilities, the most appropriate.

Mr. Gray argued that Trans Mountain could use a trenchless method of construction, the Lands had circumstances that require a trenchless method, and the adjacent properties had space within the existing encumbered areas for excavation work, such that there were no barriers. In the CER's view, although a particular method of construction may have been technically feasible, the practical ability to use that method did not necessarily mean that it is appropriate to the circumstances on the particular lands.

Mr. Gray's concern was that the temporary workspace associated with the open-cut method would destroy the wooded area and the walking path on the south part of the Lands.

Although the CER recognized that the removal of the forested area to accommodate the temporary workspace did not align with Trans Mountain's stated aim to avoid treed areas, it was of the view that the proposed temporary workspace was appropriate. The temporary workspace avoided proximity to residences and would not affect areas of environmental or cultural sensitivity, which was both appropriate and consistent with Trans Mountain's stated aims. The CER further found the temporary workspace appropriate, as it accepted that Trans Mountain required it to install the pipeline safely. The CER accepted that Trans Mountain would only clear woody vegetation to the extent required to safely construct the pipeline, such that Trans Mountain would minimize the removal of trees from the Lands. The CER also found that Trans Mountain's proposed mitigation measures for the forested area and the walking path were responsive to the Grays' concerns and were acceptable and appropriate for the Lands. The CER agreed that mitigation measures could not completely address the Grays' concerns in the short term because the only full solutions are to leave the forested area untouched or to reproduce a forest of the same state of maturity.

The CER acknowledged Trans Mountain's and the Grays' previous efforts to address the Grays' concerns by exploring the possibility of a narrower temporary workspace. In the CER's view, it was appropriate to explore this option, and it was unfortunate that the parties were unable to agree to a revised temporary workspace. The CER encouraged Trans Mountain to undertake further studies and engagement to determine if the construction footprint area could be reduced.

The CER expected Trans Mountain to fulfill the significant commitments it has made in this detailed route hearing. The CER was of the view that several of Trans Mountain's proposed mitigation measures are particularly responsive to the Grays' concerns, including Trans Mountain's commitment to consult with them to develop a site-specific reclamation plan and its proposal to establish understory vegetation of the same species along the walking path, which would also provide a visual buffer between the walking path and the lands to the south. The CER expected Trans Mountain to provide the Grays with a full list of the commitments it made to them throughout this hearing and to follow through with each one. Notably, these commitments included conducting an assessment of the existing trees and providing to the Grays an arborist report that sets out the number, species, age, size, health, and value of all the trees proposed to be removed from the wooded area and the walking path. The CER expected Trans Mountain to develop the site-specific reclamation plan in consultation with the Grays, and to consider construction activities and replanting, how these activities could be coordinated, and how reclamation of the impacted forested area could be expedited.

The CER found that Trans Mountain's proposed conventional open-cut method of construction was the most appropriate method of construction for the Lands.

Is Trans Mountain's Proposed Timing of Construction the Most Appropriate?

Trans Mountain proposes a schedule of construction as follows:

- begin tree clearing in Q4 2020 to accommodate bird nesting window restrictions;
- prepare the ROW and install the pipe between Q1 and Q2 of 2021; and
- complete clean-up and restoration in Q3 2021.

In the absence of evidence of specific concerns, the CER found that Trans Mountain's proposed timing of constructing the TMEP pipeline across the Lands was the most appropriate.

***Trans Mountain Pipeline ULC Trans Mountain Expansion Project Detailed Route Hearing MH-027-2020 - Phase 1*, CER Letter Decision**

Pipelines - Route Hearing

In this letter decision, the CER found that, subject to the Phase 2 and 3 Hearings, the route proposed by Trans Mountain Pipeline ULC ("Trans Mountain") would be the best possible detailed route of the Trans Mountain Expansion Project ("TMEP"), and the methods and timing of constructing the pipeline were the most appropriate, subject to the commitments made by Trans Mountain and continued compliance with the Certificate conditions.

Introduction and Background

On 16 December 2013, Trans Mountain applied to the National Energy Board under section 52 of the *National Energy Board Act* ("*NEB Act*") for a Certificate authorizing the construction and operation of the TMEP.

The TMEP was approved by Order in Council ("OIC") P.C. 2016-1069 in November 2016. The NEB issued Certificate OC-064 and began work on various regulatory processes, including the 2017/2018 detailed route approval process.

On August 30, 2018, the Federal Court of Appeal ("FCA") issued its decision *Tsleil-Waututh Nation v. Canada (Attorney General)*1 ("FCA Decision"), which set aside OIC P.C. 2016-1069 and remitted the matter back to the GIC for appropriate action.

Following a second public hearing process ("the Reconsideration"), the NEB issued its MH-052-2018 Reconsideration Report in February 2019. Canada's Crown Consultation and Accommodation Report were issued in June 2019. The Governor in Council ("GIC") approved the TMEP again in June 2019 via OIC P.C. 2019-820 and the NEB subsequently issued Certificate OC-065 with 156 conditions. On 19 July 2019, following a public comment process, the NEB set out how it would resume the TMEP detailed route approval process.

Hearing MH-027-2020

In response to various statements of opposition ("SOOs") filed by the S'ólh Téméxw Stewardship Alliance ("STSA"), the CER granted the STSA a hearing. The hearing had a geographic focus on the route segments to which the STSA noted its opposition in its SOOs.

Change in Geographic Scope

Following the withdrawal of all STSA member first nations as signatories to the STSA SOOs except Semá:th, and the STSA's request that Semá:th substitute it as the SOO Filer, Trans Mountain filed a notice of motion seeking a reduced geographic focus for the hearing. The CER approved the motion from Trans Mountain to reduce the geographic scope from the STSA SOO lands to the Project Route, described below.

Introduction to the Proposed TMEP on the Project Route

The scope of the hearing was limited to Kilometre Post ("KP") 1099.19 to KP 1120.52 ("Project Route").

Consultation

Trans Mountain's Consultation

Certificate OC-065, issued by the CER imposed several conditions requiring Trans Mountain to consult with potentially affected Indigenous peoples, including Semá:th. Semá:th argued that Trans Mountain did not adequately consult Semá:th when developing the Project Route. Semá:th further voiced concerns regarding Trans Mountain's consultation more generally.

Route, Methods and Timing of Construction

Trans Mountain's Routing Criteria for the TMEP

Trans Mountain stated that its pipeline corridor, as authorized in Certificate OC-065 for the TMEP, was developed based on a standard set of routing criteria designed to enable the safe installation of the pipeline, and to reinforce the protection and integrity of the pipeline while minimizing the adverse effects of pipeline installation and operation to the extent practicable. Trans Mountain stated that determining routing feasibility for the entire TMEP included consideration of a range of factors, including constructability; long-term geotechnical stability; and environmental, cultural, and socio-economic suitability.

In its Reconsideration Report, the NEB found that Trans Mountain's route selection process, route selection criteria, and level of detail for its alternative means assessment were appropriate. The NEB further found that the alignment of the majority of the proposed pipeline route alongside, and contiguous to, existing linear disturbances would be appropriate. The NEB noted this would minimize the environmental and socio-economic impacts of the TMEP.

Views of Semá:th

The STSA/Semá:th stated that it placed specific reliance on two major documents in their written evidence: the Integrated Cultural Assessment ("ICA") and the Stó:lō Heritage Policy Manual, and submitted that both of these documents should be respected and relied upon by the CER in adjudicating whether the Project Route is the best route. The STSA/Semá:th stated that the ICA concluded that the TMEP would pose a significant risk and represents a significant threat to the cultural integrity and survival of core relationships at the heart of Stó:lō worldview, identity, and well-being.

The STSA/Semá:th submitted that the TMEP would affect the claimed Indigenous title and established Indigenous rights of the Stó:lō.

The STSA/Semá:th submitted that the TMEP's interference with or impact on Stó:lō Indigenous rights, interests, cultural and spiritual practices, and heritage sites must factor into the CER's analysis of whether the Project Route is the best route.

Regarding routing principles, heritage resource, and mitigation measures, Semá:th stated that, through its representation by the STSA, it had expressed its desire for specific and different mitigation measures beyond those proposed by Trans Mountain in the Resource Specific Mitigation Table ("RSMTs").

Semá:th stated that Trans Mountain appeared to have selectively weighed the Stó:lō stewardship concerns and site-specific mitigation requirements detailed in the Stó:lō Policies. The Stó:lō Policies had been made available to Trans Mountain throughout its route planning process. Semá:th stated that Trans Mountain did not provide Semá:th with an avenue to understand how its concerns for the protection of Stó:lō cultural sites have been factored into Trans Mountain's decision-making. Semá:th argued that the proposed detailed route and the method and timing of construction are not reflective of the Stó:lō Heritage Policy Manual framework and, therefore, the route as planned should not be approved.

Views of Trans Mountain

Trans Mountain stated that Semá:th relied on the 2014 ICA, which identified concerns about the TMEP's alleged impacts on the Stó:lō Nations. Trans Mountain stated that the ICA was filed as part of the original Certificate hearing for the TMEP and the impacts identified in that report were carefully considered by the NEB, the Government of Canada and, ultimately, the GIC in its decision to approve the TMEP.

Trans Mountain stated that the concerns expressed by Semá:th relate to the overall impacts of the TMEP on Semá:th's rights and interests. Trans Mountain stated that these impacts and associated mitigations had already been considered and addressed in the GIC's decision to approve the TMEP. Trans Mountain further stated that

Semá:th's general concerns about the TMEP's impacts had also been addressed through the conditions imposed on Trans Mountain in Certificate OC-065 and related approvals.

Regarding routing principles, heritage resource, and mitigation measures, Trans Mountain stated that its focus was on minimizing the TMEP's adverse effects. This would facilitate minimizing its contribution to cumulative effects. It indicated that its proposed detailed route and construction methods and mitigation through the Project Route achieve the objective of minimizing the TMEP's adverse effects largely through paralleling the existing TMPL and other linear features to the extent practicable and implementing a comprehensive suite of mitigation measures.

Trans Mountain argued that it presented uncontested evidence that the Project Route aligned with Trans Mountain's routing principles, which were previously acknowledged and accepted by the NEB in the Certificate hearings.

CER Decision in Hearing MH-027-2020

Consultation

The CER found Trans Mountain's consultation with Semá:th and the STSA in respect of the Project Route and the methods and timing of construction was adequate. Trans Mountain began consultations with potentially affected Indigenous communities, including Semá:th, in the planning stages of the TMEP, as required by the Filing Manual. Submissions demonstrated that consultations continued after GIC approval of the TMEP and through the MH-027-2020 hearing process.

The CER found that Trans Mountain's consultations with different organizations that represented the interests of the Semá:th were appropriate, recognizing the specific requests of the individuals and organizations with whom it consulted. As the various organizations indicated that they represented the interests of several Indigenous peoples, including Semá:th, it was reasonable for Trans Mountain to engage with those organizations and rely on the information they provided.

The CER noted that numerous conditions in Certificate OC-065 would have ongoing requirements for consultation with Indigenous peoples during construction and throughout the lifecycle of the TMEP. This would include consultation on several protection and mitigation plans in the environmental protection plans ("EPPs"), as well as emergency response plans. The NEB also imposed Conditions 96 and 146 requiring Trans Mountain to report to the NEB on its consultation with Indigenous peoples during construction and through the first five years of operations.

Route, and Methods and Timing of Construction

The CER found that, subject to the Phase 2 and 3 Hearings and ongoing compliance with the Certificate OC-065 conditions, the proposed project Route would be the best possible route for the TMEP, and the proposed methods and timing for constructing the TMEP pipeline would be the most appropriate.

The CER considered the submissions relating to traditional land and resource use while noting that the detailed route approval process established by the *CER Act* is not intended to reconsider matters adjudicated in the Certificate hearings. The Reconsideration Report stated that, during construction and routine operations, the TMEP would not likely cause significant adverse impacts on the environment, resources used for traditional purposes by Indigenous communities, or the ability of Indigenous communities to use the environment or resources for traditional purposes.

The CER found that no new potential impacts relating to the detailed route were identified and noted that the Certificate OC-065 conditions contain requirements for available and applicable traditional land and resource use to be considered.

Regarding routing principles, heritage resource and mitigation measures, the CER found the Trans Mountain applied routing criteria appropriate in the circumstances.

In the Stó:lō Heritage Policy Manual, Semá:th identified that avoidance would be the preferred and, in some cases, required mitigation method regarding potential impacts to Stó:lō heritage resources. During the sharing of oral Indigenous knowledge, it was expressed that the TMEP must avoid the river, the mountain, and the aquifer. The CER found that avoidance can be achieved through the chosen routing options or construction methods. The CER also noted that, where avoidance is not possible, Trans Mountain would rely on mitigation tools based on best practices and which have been reviewed and approved during the Certificate hearings and were in practice during TMEP construction.

Conclusion

Having assessed all of the evidence, the CER was of the view that there had been adequate consultation and accommodation for the purpose of this detailed route decision. The CER found that the route proposed by Trans Mountain for those lands that were not subject to further TMEP Hearings is the best possible detailed route of the pipeline, and the methods and timing for constructing the pipeline would be the most appropriate, subject to the commitments made by Trans Mountain and ongoing compliance with the OC-065 Certificate conditions.

***Westcoast Energy Inc. Doing Business As Spectra Energy Transmission Application to Construct and Operate the Silverstar Project,* CER Letter Decision**
Pipeline Facilities

In this decision, the CER approved the application from Westcoast Energy Inc. doing business as Spectra Energy Transmission ("Westcoast") to construct and operate the Silverstar Project (the "Project").

In the application, Westcoast requested an exemption from the provisions of subsection 180(1), sections 198, 199, and 213 of *the Canadian Energy Regulator Act* (the "*CER Act")*. Westcoast further requested an order according to section 97 of the *CER Act* exempting Westcoast from the provisions of section 17 of the *Canadian Energy Regulator Onshore Pipeline Regulations* ("*OPR*") and Condition 1 of Order MO-08-2000 regarding the non-destructive examination ("NDE") of all welds for the auxiliary and utility piping systems. Westcoast also requested an order according to section 226 of the *CER Act*, that would affirm the inclusion of the cost of the Project in the Transmission North ("T-North") (Zone 3) cost of service and their tolling on a rolled-in basis.

Decision of the CER - Section 214

The CER was satisfied with the engagement activities undertaken by Westcoast. The CER further found that protection of the environment and public safety had been appropriately addressed by Westcoast. The CER further reviewed the financial viability, economic justification, and proposed design and operations of the Project. The CER accepted the rationale provided by Westcoast and found that it was in the public interest to grant the requested relief.

The CER issued Order XG-024-2020 (the "Order") to approve the Project. As indicated in the Order the CER exempted Westcoast from the provisions of paragraph 180(1)(a) and section 198 of the *CER Act* for the Project.

The CER partially exempted Westcoast from the requirements to obtain a Leave to Open ("LTO"), required under paragraph 180(1)(b) and subsection 213(1) of the *CER Act,* for those auxiliary and utility systems having a design pressure of 1965 kPag or less.

The CER further granted Westcoast's request for an exemption from the provisions of section 17 of the *OPR* and Condition 1 of Order MO-08-2000 related to the NDE of all welds for the auxiliary and utility piping systems which are designed and constructed in accordance with the American Society of Mechanical Engineers B31.3, and have a design pressure of 1965 kPa or less.

Based upon the scale of the Project and the nature of the surrounding environment, the CER determined that the Project would have no or negligible potential impacts on the exercise of Indigenous and Treaty Rights in the Project area. The CER also determined that the Project would have no or negligible environmental or socio-economic effects.

The CER noted that, according to Conditions 1 and 4 of the Order, Westcoast was required to file any technical specification updates for the Project components listed in the application at the time with its LTO application.

Decision of the Commission - Section 226

Regarding the request to include the cost of the new metering facility in the T-North (Zone 3) cost of service and toll it on a rolled-in basis, the CER accepted Westcoast's submissions that the addition of the Silverstar delivery facility would not functionally re-purpose the T-North system as a whole. The CER was satisfied that the T-North system, including the Sunset Creek compressor station and the delivery facilities at Sunset, would remain functionally integrated after the Silverstar facility was placed in service.

The CER was of the view that the delivery facilities at Sunset Creek and Silverstar should receive the same tolling treatment because each metering facility was performing a similar function. Accordingly, the CER found that the proposed tolling treatment for the Project would be appropriate in these circumstances.

The CER found that a reassessment of the tolling methodology for the T-North system, including the Sunset and Silverstar meter stations, was not required at the time.

The CER directed Westcoast to serve a copy of this letter decision, the attached Orders and its Schedule A on all interested parties.