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.

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ALBERTA UTILITIES COMMISSION

Measuring Regulatory Burden – Industry Impact Assessment, AUC Bulletin 2021-08

Regulatory Efficiency - Strategic Plan

In its 2021-2024 Strategic plan, published on April 26, 2021, the AUC outlined three areas on which it will focus: efficiency and limiting regulatory burden, facilitating change in the sector, and people. The plan requires the AUC to produce an annual report card describing the progress it has made in meeting the objectives associated with each strategic plan theme. A key part of the annual report card is assessing the impact on industry and stakeholders, which includes reporting cost benefits of recent efforts to reduce red tape and regulatory burden. In this Bulletin, the AUC asked stakeholders to submit what benefits and cost savings they have experienced.

The AUC noted that reducing regulatory lag and burden is not only a priority for industry and the AUC, it is also a fundamental policy goal of the provincial government. The reduction of red tape legislation directs the AUC to reduce the requirements found in its 33 rules by one-third by 2023.

Last year the AUC attempted to quantify the benefits that were experienced because of the various initiatives taken to reduce regulatory burden and lag. Although the AUC's initial assessment was focused on the AUC's own internal direct costs, as a next step, the AUC will solicit cost savings realized by utilities because of its efficiency improvements through the AUC Industry Impact Assessment tool. The AUC noted that the regulated companies are the best source of information on how the AUC's rules and processes impose a regulatory burden and what benefits result from reducing process and regulatory requirements. The AUC repeated that its goal is to evaluate the cost benefits and effectiveness of its burden reduction initiatives and to track continuous improvement through future business cycles. The industry impact assessment will form part of the AUC Annual Report Card.

The AUC attached, as an appendix, an outline describing how the assessment tool works for the AUC and invited stakeholders to assess and submit their own costs savings that have resulted from efficiency gains described in the appendix by May 19, 2021.

Stakeholder Consultation to Standardize Terms and Conditions of Electric Distribution Utilities' Connection Process, AUC Bulletin 2021-09

Distribution - Electricity

As noted as an objective in the AUC's 2021-2024 Strategic Plan, the AUC is initiating a consultation to standardize terms and conditions of service required by Alberta's electric distribution utilities to ensure customers receive consistent treatment.

The first module of the consultation will focus on establishing interconnection standards that will outline how projects owned by customers or developers will connect to the electric distribution system. The result will provide a standardized process and schedule so that interconnections can be accommodated in an orderly, cost-effective and timely manner. The second module of the consultation will focus on standardizing the terms and conditions of service for distribution utilities in Alberta.

The initial issue of the first module is connection costs, specifically how to provide customers and developers with the opportunity to pay a fair and reasonable price to connect. Regarding connection costs, the AUC will consider the following matters:

- Providing an option to customers and developers to obtain their own pricing from a third-party contractor that can meet the industry standards for facilities installation (similar to what occurs on the transmission side for electric facilities).
- Fixed-priced packages, as an example, the FortisAlberta Inc. fixed-cost options for farms and acreages.
- Establishing a maximum amount that could be charged for connection costs based on comparative studies within Alberta and from other jurisdictions.

Alberta Electric System Operator Application for Approval of New Alberta Reliability Standard ADM-002-AB-1, **AUC Decision 26407-D01-2021**
Electricity - Law

In this decision, the AUC approved the new Alberta reliability standard ADM-002-AB-1 proposed by the Alberta Electric System Operator ("AESO") pursuant to subsection 19(4)(b) of the *Transmission Regulation*.

<u>Background</u>

Section 103.14 of the Independent System Operator ("ISO") Rules, *Waivers and Variances*, which was developed to more effectively address requests for waivers and variances related to the Division 502 ISO Rules, was approved by the AUC in Decision 24885-D01-2019. The AESO found that a similar mechanism would be useful for reliability standards. Therefore, the framework of Section 103.14 is followed in the proposed new Alberta reliability standard ADM-002-AB-1. The proposed new reliability standard allows for a waiver or variance request to be submitted and approved for any new requirement in a reliability standard that does not already have its own mechanism.

<u>AUC Findings and Decision</u>

Subsections 19(5) and 19(6) of the *Transmission Regulation* require the AUC to approve or refuse to approve each reliability standard as recommended by the AESO unless an interested person convinces the AUC that the recommendation is technically deficient, or not in the public interest. No objection indicating that the proposed new ADM-002-AB-1 is technically deficient or not in the public interest was filed.

Pursuant to subsection 19(6) of the *Transmission Regulation* and based on the recommendation of the ISO, the Commission approved the proposed new ADM-002-AB-1, effective April 22, 2021.

Alberta Electric System Operator Application for Approval of New Alberta Reliability Standard PER-006-AB-1, **AUC Decision 26406-D01-2021**
Reliability Standard

In this decision, the AUC approved the new Alberta reliability standard ADM-002-AB-1 proposed by the Alberta Electric System Operator ("AESO") pursuant to subsection 19(4)(b) of the *Transmission Regulation*.

<u>Background</u>

The AESO submitted that the proposed new PER-006-AB-1 requires the operator of generating unit or aggregated generating facility to provide training to personnel who are responsible for the real-time control of the generating unit or aggregated generating facility. The operator is required to train the personal on the functionality of protection systems and remedial action schemes that affect the output of the generating unit or aggregated generating facility.

The AESO further submitted that the proposed new PER-006-AB-1 is important for maintaining the reliable operation of the interconnected electric system, as the training of operating personnel, on those protection systems that may affect the output of their machines can help expedite the restoration of a generating unit or aggregated generating facility to service, or possibly help mitigate the loss of a machine during certain operating conditions.

<u>AUC Findings and Decision</u>

Subsections 19(5) and 19(6) of the *Transmission Regulation* require the AUC to approve or refuse to approve each reliability standard as recommended by the AESO unless an interested person convinces the AUC that the recommendation is technically deficient, or not in the public interest. No objection indicating that the proposed new PER-006-AB-1 is technically deficient or not in the public interest was filed.

Pursuant to subsection 19(6) of the *Transmission Regulation* and based on the recommendation of the Independent System Operator, the Commission approved the proposed new PER-006-AB-1, effective July 1, 2023.

***Alberta Electric System Operator Compliance with Decision 25848-D01-2020,* AUC Decision 26215-D01-2021**

Review and Variance - Compliance Filing

In this decision, the AUC approved the application from the Alberta Electric System Operator ("AESO") for approval of its compliance filing to Decision 25848-D01-2020 (the "Decision"), the Stage 2 review and variance of the 2018 Independent System Operator ("ISO") tariff for the adjusted metering practice and substation fraction methodology.

The AUC addressed issues related to the Scope of the Stage 2 review and variance and ultimately found that the AESO had complied with applicable compliance directions from the Decision. The AUC also made findings related to FortisAlberta Inc.'s ("Fortis")'s compliance with an AUC direction from the Decision and provided additional directions related to the recalculation of construction contribution decisions, with additional reporting requirements for all four regulated distribution facility owners ("DFOs").

<u>Process Steps and Background</u>

The Decision reflected the AUC's determinations regarding a Stage 2 review and variance ("R&V") of certain aspects of Decision 22942-D02-2019, the AESO's 2018 ISO tariff. In Proceeding 25848, the Stage 2 panel considered submissions in respect of the application of the AESO's substation fraction ("SSF") methodology, which was unchanged in the 2018 ISO tariff application, as well as a new proposal of the AESO to implement an adjusted metering practice ("AMP") that had been approved in Decision 22942-D02-2019.

<u>Compliance Filing Directions</u>

Direction 1 – Tariff Amendments for Implementation of Substation Fraction of One

In the Decision, the AUC found that the Rate Supply Transmission Service ("STS") portion of the construction contribution applied to connection projects initiated by DFOs serving new distributed-connection generation ("DCG") projects would be set to zero, rather than on the basis of the SSF formula as currently defined in the AESO's *Consolidated Authoritative Document Glossary* ("Glossary"). The AUC had issued Direction 1:

> 28. The Stage 2 panel directs the AESO to file its compliance filing to this decision by January 11, 2021, with the necessary tariff amendments to implement the SSF=1 proposal.

The AESO prepared a revision to its definition of substation fraction as an update to its Glossary, and proposed revisions to subsection 4.5(5) of the ISO tariff terms and conditions ("T&Cs"). The AESO noted that the revisions would remove the requirement to deem costs related to a DFO's Rate STS capacity to be "supply-related costs", and instead, costs related to a DFO's Rate STS capacity are deemed to be zero. With these amendments, no costs associated with Rate STS would be used to determine the DFO's construction contribution.

The AUC found that the proposed amendments were reasonable and approved them as filed.

Directions 8, 9, and 10 – Revised Tariff Language for Implementation of AMP

The AESO proposed changes to subsections 3.2(2), 3.6(2), and 3.6(3) of the ISO tariff T&Cs, which refer to *Applying for a System Access Service or Change to an Existing System Access Service* and *Execution of Agreement for System Access Service*, respectively. The changes referred to the implementation of the AMP and whether a market participant is obliged to contract for system access service ("SAS") on a net or gross basis. The proposed changes to subsections 3.2(2), 3.6(2), and 3.6(3) of the ISO tariff T&Cs were approved.

The AESO's proposed revisions to subsection 3.6(4) related to the circumstance under which a market participant may execute a *System Access Service Agreement* for Rate demand transmission service ("DTS") or Rate STS at a contract capacity. The AESO indicated that the revised version of subsection 3.6(4) eliminated provisions proposed by the AESO in Proceeding 25175 that gave effect to a grandfathering approach of the AMP that was approved by the AUC in Decision 22942-D02-2019. Proceeding 25175 required revision in accordance with determinations of the Decision that the AMP should be implemented with no grandfathering provisions. The AESO was requested to clarify how the approval of the ISO tariff T&Cs changes would affect the ability of industrial complexes to continue to be billed for ISO tariff charges on a net rather than on a gross basis. This included scenarios where the industrial complex is not an AUC-designated industrial system, or a market participant that has received AUC approval to both self-supply load and export excess electric energy to the grid.

The AESO submitted that during Proceeding 22942, the AESO determined that net billing was inapplicable for industrial complexes that have not obtained an industrial system designation ("ISD") under Section 4 of the *Hydro and Electric Energy Act* or that are not otherwise subject to an exemption in respect of the energy produced by the industrial complex. It noted as with all other provisions set out in Section 3 of its ISO tariff T&Cs, subsection 3.6(4) would only apply to existing market participants if they request a change to SAS at an existing point of delivery or supply to the transmission system.

Interveners raised concerns about the potential impact of the AMP on the continuation of net billing of industrial complexes and proposed further changes to subsection 3.6(4) to allow market participants to continue to be billed on either a net or a gross basis following changes to SAS agreements, if changes were made regarding a SAS agreement executed before January 1, 2021.

In the Decision, the AUC made clear findings that the AMP should be implemented without grandfathering. Considering these clear findings, the AUC denied amendments to subsection 3.6(4) proposed by interveners. The AUC pointed out that subsection 3.1(1) limits the operation of subsection 3.6(4) to instances where the SAS agreement is newly entered or amended. This means that market participants that have previously been able to elect to be billed on a net rather than a gross basis can continue to do so if they do not initiate SAS agreement amendments.

The AUC invited a discussion of whether industrial complexes who receive SAS through a DFO may be at risk to SAS change requests by the DFO and not by the industrial complex themselves. In response, the Consumers' Coalition of Alberta and the AESO agreed that transmission-connected customers that did not initiate a change in their SAS agreements would not be exposed to risk arising solely from the implementation of the AMP. They also agreed that under the AMP, a distribution-connected industrial complex might be exposed to the risk of cost consequences arising from SAS changes requested by the DFO.

The AUC considered that industrial complexes that are flow-through end-use customers of a DFO should not be subject to the risk that they do not directly control arising from contract changes initiated by a DFO. It noted that risk to industrial complexes who receive SAS indirectly as a flow-through end-use customer of a DFO is a limitation of the proposed implementation of the AMP that cannot be fully addressed within the ISO tariff, as this involves the DFO tariff.

The AESO outlined how specific anticipated impacts would differ for active DFO connection projects, depending on whether the active DFO project has, or has not, executed a SAS at the time the ISO tariff provisions above come into effect. The AESO's proposed wording of subsection 3.6(4) was approved.

The AUC found the remainder of the changes to the T&Cs were administrative in nature, and approved them.

Direction 4 and 5 Recalculation of Construction Contribution Decisions and Reporting of Disputes

In the Decision, the AUC addressed a concern that the application of the SSF formula in effect prior to that decision may have allocated costs beyond the incremental costs arising from Rate STS contract requirements for some existing DCG projects connected to substations where the DFO is the market participant. The AUC found that it should not be applied to construction contribution decisions ("CCDs") for connection projects at DFO-contracted substations to which DCG connects. Accordingly, the AUC issued Direction 4 that required the AESO to recalculate CCDs using SSF=1 and the principles articulated in Section 3.5 of this decision and to inform affected DFOs of those recalculations.

In Direction 5, the AUC required each DFO to file a report setting out the details of all resolutions and outstanding disputes related to existing DCG projects connected to DFO-contracted substations on or before March 31, 2021. The AUC found that EPCOR Distribution & Transmission Inc., ENMAX Power Corporation, Fortis and ATCO Electric Ltd. had complied with this direction.

However, the AUC did not review CCDs that the AESO intended on revising. The AUC found it concerning because the AESO stated that its "recalculation of CCDs would confirm that there are zero supply-related costs for DFO points of delivery and supply" prior to having completed its recalculation of specific CCDs. Further, the AESO did not discuss the inputs required for the AESO's CCD recalculation with the DFO. To facilitate needed clarification, the AUC required a "re-do" of Direction 5. The AESO was directed to complete the preparation of all required CCD recalculations and to forward such recalculated CCDs to the applicable DFO. DFOs were directed to then advise the AESO of any disputes with recalculated CCDs. DFOs are to advise any DCGs impacted by the revised CCDs. Finally, the DFOs were directed to provide an additional report on any disputes with DCG proponents that may have arisen following the communication of both the recalculation of CCDs and any resulting flow-through of supply-related costs that the DFO has determined should apply to the DCG by November 1, 2021.

Effect of the SSF=1 Approach on Historical DTS POD Charges

The AESO submitted that after recalculating historical CCDs in accordance with the SSF=1 proposal, fairness and market efficiency might require that historical Rate DTS bills be adjusted in some circumstances. The AESO also indicated that because it believes that the rebilling of Rate DTS charges may have other distribution tariff impacts, it intended to work with DFOs to determine whether rebilling Rate DTS charges is appropriate.

Considering the potential issues arising from rebilling of Rate DTS, the AESO requested that the AUC confirm that the AESO could proceed in the manner it described in the application. The AESO noted that its concern was primarily related to the potential impact of such rebilling on DFO tariffs. The AUC noted that rebilling of historical DFO POD charges was not addressed in any of the Direction 5 submissions filed by the DFOs. However, the AUC found that any potential rebilling of Rate DTS POD charge costs related to those substations that would receive SSF=1 to address historical costs back to December 1, 2015, may not be sufficiently material to warrant further examination by the AESO or the DFOs. The AUC directed the AESO to discuss with DFOs whether further examination of this matter is warranted and to include the outcome of those discussions in the AESO's deferral account reconciliation application.

Direction 7 – Fortis Update on Response to BluEarth Complaint

In the Decision, Fortis was directed to provide details of a proposal for the disposition of its deferral account established to deal with the complaint of BluEarth Renewables Inc. considered by the AUC in Proceeding 25058. Fortis submitted that the deferral account contained a balance of $2,145,216 for a payment made to AltaLink Management Ltd. ("AML") for Fortis's 257S Hull DER Solar project. Fortis noted that following the receipt of a recalculated CCD for that project, it was anticipated that AML would refund this payment to Fortis, and the corresponding deferral account would be closed. The AUC determined that Fortis had complied with Direction 7.

<u>Effective Date of Approved ISO Tariff Changes</u>

The AUC applied a single effective date of July 1, 2021, for the revised ISO tariff based on this decision.

<u>Direction 11 – AMP Implementation Plan and Timing of AMP Changes</u>

In response to Direction 11, the AESO confirmed its intention to submit an implementation plan setting out the details of how to operationalize the AMP as part of its Phase 2 tariff application. Following a request from the AUC, the AESO submitted that it would be appropriate and efficient to file its AMP implementation plan in 2021, separately and before its Phase 2 tariff application in 2022. This would provide certainty to market participants regarding how the AMP would be implemented as soon as possible. The AESO was directed to file an application in respect of a proposed AMP implementation plan on or before January 1, 2022, with further amendments to incorporate AMP requirements into ISO Rule 502.10.

AltaLink Management Ltd. 2013-2023 Tariff Refund, AUC Decision 26248-D02-2021

Rates - Refund

This decision discussed the reasons for approving, in part, AltaLink Management Ltd.'s ("AML")'s 2021-2023 tariff refund application. AML's proposal was not accepted as applied for. The amount of the tariff refund and the period over which the refund will be made was revised. In Decision 26248-D01-2021, the AUC found a 2021 tariff refund in the amount of $230 million, which results in a net 2021 tariff reduction in the amount of $223,512,7813 and net monthly tariff for April to December 2021 in the amount of $45,851,942 to be just and reasonable.

<u>Introduction</u>

On January 18, 2021, AML filed an application for approval of a proposed 2021-2023 tariff refund. AML proposed to refund $150 million of previously collected future income taxes ("FIT") and $200 million of accumulated depreciation surplus, which would result in a reduction to its transmission tariff of $131.2 million in 2021, $123.6 million in 2022, and $62.5 million in 2023.

After a notice of application was filed, Alberta Direct Connect Consumers Association ("ADC"), the Consumers' Coalition of Alberta ("CCA"), the COVID Relief Alliance ("CRA"), the Industrial Power Consumers Association of Alberta ("IPCAA"), the Alberta Electric System Operator ("AESO") and the Office of the Utilities Consumer Advocate ("UCA") registered as participants.

<u>Proposed Tariff Refund</u>

The FIT Refund Approved in Decision 26248-D01-2021 Does Not Offend the Prohibitions Against Retroactive and Retrospective Ratemaking

AML had proposed to refund previously collected FIT in the amount of $150 million. Contrary to concerns raised by the CCA and the AESO, the AUC determined that the proposed refund does not offend the prohibitions against retroactive and retrospective ratemaking. The AUC had approved FIT for AML, on a temporary basis, to provide credit metric relief during a period of strong capital build by allowing AML to pre-collect income tax amounts before they needed to be paid.

AML had requested to implement a FIT refund in 2021-2023, effective as soon as possible following AUC approval. The AUC determined that this request does not constitute retroactive ratemaking because the requested refund implementation date is after the date of the decision. The relief would therefore be effective on a prospective basis. The AUC noted that contrary to replacing or substituting the final amounts collected from ratepayers in prior periods under the FIT method, refunding previously collected FIT amounts to ratepayers on a prospective basis is not retroactive.

The AUC determined that AML's proposal is not retrospective because it does not seek to remedy a past rate order's deficiency in future rates. The AUC noted that the FIT amounts previously paid by AML customers and the findings related to the approval of those payments would not be disturbed by this decision. AML no longer required credit metric relief and did not anticipate paying income tax for approximately 24 years until the point of cross-over. AML's proposal concerns how the FIT balance paid by past ratepayers should be distributed to current and future ratepayers, and the AUC was satisfied that the proposal mitigates concerns regarding intergenerational equity. The AUC noted that the proposal made it likely, that those ratepayers that paid into the FIT balance would be the ones receiving a refund.

The AUC noted the exceptional circumstances faced by ratepayers due to the COVID-19 pandemic. It found it necessary to consider all possibilities of rate relief in 2021. It also noted that considering the effect of the COVID-

19 pandemic, even if the proposal from AML resulted in retroactive or retrospective ratemaking, applying these principles strictly in the circumstances would not result in sound utility regulation.

The Tariff Refund Approved in Decision 26248-D01-2021 Results in Just and Reasonable Rates

In Decision 26248-D01-2021, the AUC approved a tariff refund in the amount of $230 million to be refunded in 2021. It found that the timing and quantum of the FIT and accumulated depreciation surplus amount to be refunded by AML to Alberta ratepayers result in just and reasonable rates.

The AUC acknowledged that, all else being equal, the refund of $230 million decreases 2021 rates but leads to an increase in 2022 rates. This increase would be a result of the debt and equity return costs associated with the FIT and accumulated depreciation surplus refunds, and the accompanying increase in rate base. However, the exceptional circumstances faced by Albertans and businesses in 2021, including the effects of the COVID-19 pandemic and the collapse in world oil prices, brought an unprecedented need for immediate ratepayer belief. The AUC noted that in these circumstances, the relief should not be unduly diminished by undue adherence to ratemaking principles and that some immediate and temporary ratepayer relief is warranted. Considering the timing of the refund, the AUC found that the exceptional circumstances of 2021, noted above, made the approved timing preferable to the refund over a longer period, such as 2021-2022, as was proposed by AML.

AML had proposed a refund of the accumulated depreciation (life) surplus of $200 million. The amount was calculated on the basis of its proposed December 31, 2019, depreciation study. The AUC could not fully test the proposed depreciation study in the current proceeding and rejected both the amount of accumulated depreciation surplus and the method used to calculate that amount. AML then updated its accumulated depreciation surplus calculation to rely on the application of the service life and Iowa curve depreciation parameters submitted by AML in its December 31, 2017, depreciation study, which had been approved by the AUC. The technical update calculations showed that while the total accumulated depreciation (life) surplus in December 2019 was $160 million, a 2021-only refund in the amount of $80 million would leave a remaining balance of $80 million of accumulated depreciation.

The AUC therefore found that a 2021 tariff refund in the amount of $230 million, consisting of $150 million in FIT and $80 million in accumulated depreciation, would result in a just and reasonable tariff. AML's compliance with the net tariff reduction ordered in Decision 26248-D01-2021 resulted in a revised 2021 net monthly tariff of $45,851,942 for April through December 2021.

AltaLink Management Ltd. 2016-2018 Deferral Accounts Reconciliation Compliance with Directions from Decision 24681-D01-2020 and Decision 25369-D01-2020, **AUC Decision 26278-D01-2021**
Compliance Filing - Rates

In this decision, the AUC found that AltaLink Management Ltd. ("AML") had complied with the AUC's directions issued in Decision 24681-D01-2020 and Decision 25369-D01-2020. The AUC further approved carrying costs on 2017 deferral account adjustments and 2017 cancelled projects costs, as filed. The AUC found that AML's direct assigned capital deferral account ("DACDA") application support costs were not all prudently incurred.

Introduction and Background

AML filed a compliance filing application pursuant to the AUC's order in Decision 24681-D01-2020. AML requested approval of its compliance with directions from Decision 24681-D01-2020 regarding AML's 2016-2018 DACDA reconciliation. The application also provided AML's responses to directions from Decision 25369-D01-2020 regarding the Edmonton Region Project DACDA reconciliation. The AUC found:

- AltaLink complied with directions 1 and 2 from Decision 25369-D01-2020;
- AltaLink complied with directions 4, 5, 6 and 7 from Decision 24681-D01-2020;

- AltaLink's DACDA application support costs (internal labour costs used to prepare and support AltaLink's 2016-2018 DACDA reconciliation application) of $2,400,829 were not all prudently incurred. The AUC approved all of AltaLink's applied-for Proceeding 25369 DACDA application support costs, but applied a disallowance totalling approximately $200,000 in respect of a portion of AltaLink's Proceeding 24681 DACDA application support costs; and

- carrying costs on 2017 deferral account adjustments and 2017 cancelled projects costs, pursuant to Rule 023: Rules Respecting Payment of Interest, were approved as filed.

The Consumers' Coalition of Alberta ("CCA") participated in this proceeding and expressed concerns with the magnitude of AML's DACDA application support costs. The AUC determined allowed information requests ("IRs") to test the reasonableness of AML's DACDA application support costs.

Compliance with Directions from Decision 25369-D01-2020 and 24681-D01-2020

Directions 1 and 2 of Decision 25369-D01-2020, 5 to 7 of Decision 24681-D01-2020

The AUC has reviewed the application and all applicable attachments and was satisfied that the AML complied with the directions. The directions related to

- reduction of legal and related costs for negotiating and concluding a Cooperation Agreement (Directions 1 and 2 of Decision 25369-D01-2020); and

- reduction of total requested cumulative capital additions for the Medicine Hat Project and the Hazelwood Project to December 31, 2018, of $186,682,308 by 2.5 per cent and $67,801,980 by 1.5 per cent, respectively (directions 5 to 7 of 24681-D01-2020).

Direction 4 of Decision 24681-D01-2020: AML's DACDA Support Costs

In Decision 24681-D01-2020, the AUC found that while AML's DACDA application support costs could be capitalized, AML had not quantified those costs on the record of that proceeding. Accordingly, in Direction 4 of Decision 24681-D01-2020, AML was directed to provide the quantum, as well as a brief explanation of the nature, of those costs in its compliance filing application.

The AUC agreed with submissions from the CCA that costs claimed for implied full-time equivalents were excessive. The AUC further took issue with the reasonableness and prudency of documentation filed by AML in support of its 2016-2018 DACDA application and with the magnitude of DACDA support costs, specifically costs associated with AML's enhanced filing approach for DACDA applications. Previous to this proceeding, the support costs associated with making filings under the enhanced approach were not known until this current proceeding.

Given the information that was available in this proceeding, the AUC determined that the value of the enhanced filing approach, first suggested by AML itself, is not commensurate with the quantum of DACDA support costs incurred by ratepayers in order for AML to affect such filings. The AUC found that a disallowance of the directly charged Proceeding 24681 DACDA application support costs incurred by AML prior to July 2019 was necessary. Accordingly, AML was directed to reduce the amount of $1,311,050, incurred prior to 2019, by 15 per cent, or by $196,658. The AUC approved the $230,527 directly charged Proceeding 24681 DACDA application support costs, incurred in July 2019, as reasonable.

AML was directed to quantify DACDA support costs of Proceeding 24681 that were included in the capital addition amounts for which AML sought approval in its 2019 DACDA application and to justify these costs. AML indicated that its DACDA application for the year 2020 would not include any projects with a cost above its threshold of $25 million, applied to submit documents under the enhanced filing approach. The AUC was reluctant to set out new filing requirements for future DACDAs within this compliance filing decision. However, should AML wish to propose specific amendments to its filing requirements prior to filing any future DACDA application, the AUC would consider such a request.

Carrying Costs - Deferral Account Adjustments and Cancelled Project Costs

AML sought to recover carrying costs on its 2017 deferral account adjustments and 2017 cancelled project costs under Rule 023. Issues arose regarding the requirement of AML to seek approval of an estimate for carrying costs under Section 3(3) of Rule 023. However, the AUC noted that AML would not have been aware of the AUC's direction requiring compliance with Section 3(3) until after filing its 2016-2018 deferral account reconciliation application. The AUC approved the carrying costs on 2017 deferral account adjustments and 2017 cancelled project costs requested by AML.

Regarding Section 3(2)(e): Rule 023 interest rate, the AUC referred to its findings in Decision 24375-D01-2020. Consistent with that decision, AML was advised that, if it requested carrying costs on cancelled project costs in the future, the AUC, when determining whether the request is reasonable, will take into consideration AML's efforts to settle the cancelled project costs at the earliest reasonable opportunity.

Order

As part of the compliance filing to Decision 25913-D01-2021, the next general tariff application, or in another future application that AML finds appropriate, AML was directed to refile its 2016-2018 deferral account reconciliation application to reflect findings and directions of this decision.

ATCO Electric Ltd. 2015-2017 Transmission Deferral Accounts and Annual Filing Adjustment Balances Compliance Filing, **AUC Decision 26247-D01-2021**
Compliance Filing

This decision sets out the AUC's findings in approving the application from ATCO Electric Ltd. ("AE") for disposal of its 2015-2017 Transmission deferral accounts annual filing for adjustment balances compliance filing to Decision 24375-D01-2020.

Introduction and Background

AE had requested the following adjustments to its deferral accounts and annual adjustments to be paid or (refunded) for Decision 24375-D01-2020:

	2014	2015	2016	2017	Total
	($000)				
Deferral accounts					
Direct Assigned Capital	-	(25,236)	2,881	1,553	(20,822)
2017 AFUDC Income Tax	-	-	-	(3,477)	(3,477)
Deducting Deferral	58	3,351	(578)	1,377	4,209
Capital Repairs	-	(431)	(255)	(758)	(1,444)
ROW [right of way] Payments	-	(171)	(20)	(153)	(345)
Property Tax	-	(13)	(1,841)	(6,838)	(8,692)
Pension Special Payment	(495)	-	-	-	(495)
Long-Term Debt Rates	-	-	-	(63)	(63)
Total Deferral Accounts	(437)	(22,500)	187	(8,378)	(31,129)
Annual filing for adjustments					
Cancelled projects	-	623	3,760	18,304	22,687

Carrying charges					
Interim to final rates	-	1,553	(2,331)	-	(778)
Cancelled projects	-	100	-	-	100
Deferral accounts	(83)	(3,377)	-	-	(3,461)
Total annual adjustments	(83)	(1,101)	1,429	18,304	18,548
Total (refund) / collection	**(520)**	**(23,601)**	**1,615**	**9,926**	**(12,580)**

Compliance with Directions from Decision 24375-D01-2020

In Decision 24375-D01-2020, the AUC had issued directions regarding AE's calculation of carrying costs. As the AUC had approved the 2015 and 2016 final tariffs on November 21, 2017, AE had been directed to remove carrying cost for December 2017 from its calculations. AE was also directed to adjust its calculations by applying actual Bank of Canada Rates to its calculations for the period of March 2019 to November 2020. AE was also directed to make any necessary changes to the forecast settlement dated with the AESO.

AE was further directed to remove costs from its calculations. The AUC had determined that business training courses were not directly attributable to bring the assets related to those courses into operation. Costs of the training courses were accordingly disallowed. The AUC further found that AE had not made sufficient effort to recover costs of tower jacking from the contractor. In relation to the Eastern Alberta Transmission Line, invoices had been miscoded, and the AUC directed that the miscoded charges of $2,529 be removed from the project costs. As the amount of allowance for funds used during construction ("AFUDC") had been imprudently incurred, AE was also directed to remove these costs in this compliance filing.

The AUC found that, in this compliance filing, AE had removed the necessary costs as directed and complied by the directions.

The AUC had directed AE to file supplementary information regarding incurred legal fees. Specifically related to the rates charged to AE, how these relate to the rates of other legal service providers and to the flat rate discount attributed to AE, considering the long-standing relationship AE has with Bennett Jones LLP and the volume of work directed to Bennett Jones LLP. To adjust for the differences in rates between Bennett Jones and other firms that AE had not sufficiently justified, the AUC directed that legal fees recorded at the associate level as charged to the DACDA projects for all years at issue be reduced by 20 per cent. As Bennett Jones LLP had introduced a flat rate discount on the legal fees charged in 2016 and 2017, the AUC directed that this be applied to fees incurred in 2015 as well.

The AUC found that in this compliance filing, AE had supplied enough supplementary information to comply with the directions. It noted that, for all future applications, it would be helpful if AE disclosed all costs incurred for all years included (capitalized) in the subject DACDA, broken down by year.

Finally, AE was directed to include the refund/collection calculation for the differences in 2017 AFUDC tax inputs between the forecast and actual costs as part of its settlement of deferral account balances.

AE submitted that there was an ongoing review and variance ("R&V") proceeding regarding the calculation of AFUDC tax inputs. That proceeding could impact the AFUDC approved in Decision 24375-D01-2020. As a result, AE requested placeholder treatment for the 2017 AFUDC tax inputs. As directed, AE included the calculated refund for the differences in 2017 AFUDC tax inputs between the forecast and actual costs:

2017 direct assigned AFUDC tax inputs

	AUC-directed method	AE proposed method in Proceeding 25938
	($ million)	
AFUDC tax impact	(3.48)	(2.57)
Deducting deferral impact	0.49	0.36
Total refund	**(2.99)**	**(2.21)**

The AUC noted that an R&V application does not amend or stay previously issued directions or decisions. However, considering the impact the R&V proceeding may have on the calculations of this proceeding, the AUC would not finalize the 2017 direct assigned AFUDC tax inputs at this time and granted AE's request for placeholder treatment of the 2017 AFUDC tax inputs pending the outcome of the R&V proceeding (Proceeding 25938). The AUC approved the refund of $2.99 million for the difference in 2017 AFUDC tax inputs.

Other Matters

AE had requested clarification on the AUC's decisions on carrying costs related to the 2017 interim tariff, 2016 and 2017 cancelled projects, and 2016 and 2017 deferral accounts. The AUC found that it had been clear and that no clarification was needed.

AE further requested clarification of directions issued regarding future requests to recover carrying costs. The AUC responded that AE was in the best position to know when a project is cancelled and when its next filing with the AUC would occur. Therefore, and as AE is aware of the applicable rules, the AUC determined that AE is in the best position to assess the earliest opportunity to request carrying costs.

Finally, the AUC was satisfied that AE had, as directed, corrected the revised refund for the 2016 and 2017 property taxes and the operating and maintenance amount as part of revised pension special payment charges, were necessary.

ATCO Electric Ltd. - Decision on Preliminary Question Application for Review of Decision 24805-D02-2020 2018-2019 General Tariff Application Compliance Filing, AUC Decision 25938-D01-2021

Review and Variation - Compliance Filing Requirements - Admissible Evidence

In this decision, the AUC allowed, in part, an application filed by ATCO Electric Ltd ("AE") requesting a review and variance of the AUC's directions in Decision 24805-D02-20202 (the "Compliance Decision") related to the issues of income tax expense and severance costs in respect of the preliminary question of whether a reviewable error exists.

Background and the AUC's Review Process

The Compliance Decision provided the AUC's determinations on the application of AE for its compliance with AUC directions in Decision 22742-D01-20193 ("Original Decision") on ATCO Electric's 2018-2019 general tariff application ("GTA").

The AUC's authority to review its own decisions is discretionary and is found in Section 10 of the *Alberta Utilities Commission Act*. *Rule 016: Review of Commission Decisions* sets out the process for considering an application for review.

The review process has two stages. In the first stage, a review panel decides if there are grounds to review the original decision (the preliminary question). If the review panel decides to review the decision, it moves to the second stage, where it decides whether to confirm, vary, or rescind the original decision.

AE alleged in its review application that the compliance panel erred in fact, law and/or jurisdiction:

(a) by denying the severance costs incurred by AE in accordance with the Original Decision; and

(b) in directing certain adjustments to tax expense and minimum filing requirement schedules to comply with the AUC's findings to recalculate its income tax expense to adjust for the allowance for funds used during construction ("AFUDC").

<u>Severance Costs</u>

For the reasons set out below, the AUC found that AE has not shown, either on a balance of probabilities or on the face of the Compliance Decision, that an error in fact, law or jurisdiction exists in the Compliance Decision in relation to the approval of severance costs that could lead the AUC to materially vary or rescind the Compliance Decision respecting severance costs.

In the original proceeding, the hearing panel found that the allocation of severance costs to AE was not reasonable because, instead of reflecting an employee's years of service with AE as a proportion of the total years employed within the ATCO group of companies, AE allocated the entire cost of severance to AE, regardless of the severed employee's work history with any of the other ATCO entities. The hearing panel instructed AE to recalculate the severance amounts.

In its compliance filing, AE provided new evidence of additional years of work history for the 2003-2013 period for AE employees severed in 2018. AE also filed evidence of positions severed from other ATCO companies with a history of prior service to AE. Some of these positions were identified in the original proceeding, and some were not.

The compliance panel found that, except for information relating to the years 2014 to 2018, none of this evidence was provided on the record of the original proceeding. The compliance panel accepted the evidence of the positions severed from other ATCO companies with a history of prior service to AE and identified in the original proceeding, but only for the years 2014-2018. The compliance panel found that the evidence in this category was "consistent with the purpose of a compliance filing…as this gives effect to the 'interrelated impact' of the AUC's findings…" and on the basis that it was first raised in the original proceeding.

In the review application, AE asserted that the compliance panel's decision resulted in the denial of $3.3 million in severance costs for 2018 and that the compliance panel made numerous errors of fact, law or jurisdiction.

The AUC held that the review application is related to a compliance filing decision, which has a more restricted purpose than an original proceeding. As noted by the compliance panel, the purpose of a compliance filing is to provide the utility with an opportunity to reflect the full and interrelated impact of all the AUC findings, and it is inappropriate for a party to introduce new evidence in a compliance filing. It is not the review panel's role to retry the application based upon its own interpretation of the evidence, nor is it to second guess the weight assigned by the compliance panel to various pieces of evidence absent an error of fact, law or jurisdiction that is either apparent on the face of the decision or otherwise exists on a balance of probabilities that could lead the AUC to materially vary or rescind the decision.

The AUC found that it was within the compliance panel's discretion to determine what evidence was responsive to the direction on severance costs. In establishing compliance with a GTA decision, the AUC is not obligated or otherwise required to accept the evidence of the applicant regarding its costs if the evidence adduced is beyond what is required for compliance with the direction. The AUC further agreed with the compliance panel that "with proper diligence," and for AE to meet its onus, it should have been able to produce work history evidence back to 2004 in the original proceeding.

Income Tax Expense

AFUDC represents the financing cost of a capital asset during the construction phase of a project. It is only calculated and included in the cost of a capital asset if the construction of the capital asset exceeds one year. When a utility calculates AFUDC, one of the inputs used is the weighted average cost of capital, which consists of a debt component and an equity component. AFUDC is not an operating expense, and it is not included as a separate revenue requirement item. Instead, recovery of AFUDC commences in the year that the capital asset to which AFUDC applies is included as part of the rate base, and the utility includes a return on that rate base as well as a return of that rate base through depreciation.

In its review application, AE challenged the basic findings of the compliance panel and alleged that those findings result in an unsupported assumption that the regulatory income tax expense over the life of a capital asset should be the same for a non-AFUDC capitalized asset and for a capital asset that includes AFUDC. AE submitted that the AUC-directed accounting for AFUDC in the calculation of regulatory income tax expense was, in part, not correct. AE disclosed, for the first time in the review application, that it had made an inadvertent error in its accounting for AFUDC in the calculation of regulatory income tax expense. AE stated that it had improperly added the debt portion of AFUDC to the utility earnings before tax. To correct its identified error, AE proposed to adjust its regulatory income tax expense by removing the debt portion of AFUDC from the total utility earnings before tax.

The AUC held that there were two concerns that arise in respect of AE's review submission on the accounting for AFUDC in the calculation of regulatory income tax expense. The first is that AE only recently disclosed that it had made an error with respect to how it accounts for AFUDC in the calculation of regulatory income tax expense. The second was that AE's discovery of its error means that it was not properly calculating the regulatory income tax expense component of its revenue requirement in the past, including in years prior to the test period, to the detriment of customers. In fact, AE acknowledged that under its historical methodology, no effective income tax deduction for the debt portion of AFUDC was reflected in the calculation of the regulatory income tax expense, and this resulted in an overstated revenue requirement.

The AUC noted AE had filed new evidence in this proceeding, which should, in the AUC's view, have been discoverable prior to the review proceeding and which AE had the clear onus to adduce in response to the direction in the original proceeding. AE's failure to exercise the diligence required to adequately respond to the AUC's original direction in this respect, which would have uncovered the error in its accounting for AFUDC in the calculation of the regulatory income tax expense, was neither efficient nor helpful to the regulatory process. Further, AE's error has resulted in the overcharging of customers and has unjustifiably benefitted the shareholders of AE in past rates.

Despite these reservations, based on the material presented in the review application, the AUC found that there was an error in the Compliance Decision in the AUC-directed regulatory accounting for the equity portion of AFUDC in the calculation of income tax expense that requires correction. AE was directed in the Compliance Decision to exclude both the debt and equity components of AFUDC from total utility earnings before tax and to include deductions for both components.

The AUC held that the correct accounting, for regulatory purposes, requires AE to include the equity portion of AFUDC as part of the total utility earnings before tax, but not the debt portion. The accounting then requires a deduction for the equity portion, which results in no net deduction for the equity component of AFUDC being reflected in the regulatory income tax expense. The accounting also requires a deduction for the debt portion, which reduces the revenue requirement.

The AUC accepted that a net equity deduction is not permissible for statutory income tax purposes. The equity component of AFUDC is the portion of the financing expense funded by equity, for which there is no offsetting expense, unlike the portion funded by debt, which has an offsetting interest expense that is deductible for statutory income tax purposes. For regulatory purposes, the AUC deemed that the financing expense is funded by debt and equity by allowing the AFUDC amount to be calculated using the weighted average cost of capital. The benefits customers receive from the AFUDC amounts for a given year arise because of the deduction of the debt portion of AFUDC in the calculation of regulatory income tax expense, which reduces that expense and lowers the revenue requirement.

The AUC, as a final matter, noted that this review decision and the second stage review decision will not only affect the calculation of income tax expense in the 2018-2019 test years but will also impact AE's income tax expense included in future applications, including the 2020-2022 GTA compliance filing. It will also affect AE's 2017 income tax expense because an adjustment would be required to the income tax expense related to the refund/collection calculation for the differences in 2017 AFUDC tax inputs between the forecast and actual costs as part of its settlement of deferral account balances.

The review panel directed AE to indicate in its second stage review application where it proposes to address the final settlement of the placeholder of $2.99 million for its 2017 income tax inputs between forecast and actual costs and where it proposes to update its revenue requirement schedules for its 2020-2022 GTA forecasts to adjust its income tax expense

Decision

In answering the preliminary question on the issue of AE's 2018 severance costs, the AUC found that AE did not demonstrate the existence of an error of fact, law or jurisdiction that is apparent on the face of the decision or otherwise exists on a balance of probabilities that could lead the AUC to materially vary or rescind AE's 2018-2019 GTA Compliance Decision and consequently dismissed the application for review on this ground.

In answering the preliminary question on the issue of income tax expense and, more specifically, the accounting for AFUDC in the calculation of regulatory income tax expense, the AUC found that a reviewable error exists, and the application for review was therefore granted. AE was directed to file, by May 5, 2021, a second stage variance application to accord with the AUC's findings.

ATCO Gas, a Division of ATCO Gas and Pipelines Ltd. 2021 Transmission Service Charge (Rider T), AUC Decision 26378-D01-2021

Rates - Transmission Service Charge

In this decision, the AUC approved the 2021 transmission service charge rider (Rider T) rates for ATCO Gas, a division of ATCO Gas and Pipelines Ltd. Effective May 1, 2021, the approved Rider T rates are:

- low-use customers: $1.125 per gigajoule ("GJ");
- mid-use customers: $1.106 per GJ;
- high-use customers: $0.259 per day of GJ demand; and
- alternative technology and appliance delivery service ("ATA") customers: $1.125 per GJ.

Background

ATCO Gas flows the rates charged by the transmission service provider through to its customers. The transmission service provider is NOVA Gas Transmission Ltd. ("NGTL"). Rider T is the service charge used to collect forecast transmission costs and to refund or collect any differences between the prior year's forecast and actual costs.

As of the AUC's approval in Decision 22328-D01-2017, ATCO Gas has added an extra step in calculating the Rider T amount. In this step, a rate group's prior year overcollection or undercollection is refunded to, or collected from, the rate group that generated the imbalance. ATCO Gas used this approved methodology to calculate Rider T in this application.

The AUC approved the current ATCO Gas Rider T rates for 2020 in Decision 25646-D01-2020. On November 26, 2020, NGTL received approval from the CER for 2021 interim rates, tolls and charges for the Alberta system. Effective January 1, 2021, the NGTL interim FT-D3 rate increased from $8.00/GJ per month to $9.27/GJ per month. The NGTL abandonment surcharge decreased from $0.20/GJ per month to $0.19/GJ per month. ATCO Gas requested approval for new Rider T rates to account for changes in the NGTL interim FT-D3 rate.

Discussion of Issues

Cross-Subsidization Between North and South Customers

Cross-subsidization issues following the implementation of a province-wide Rider T rate were discussed by the AUC in previous decisions. As part of these discussions, the AUC had required ATCO Gas to discuss what measures it took to minimize cross-subsidization between north and south customers and to provide analyses to assist the AUC to assess whether the province-wide implementation of a Rider T rate had resulted in substantial cross-subsidization between north and south customers.

ATCO Gas indicated that the primary contributor to cross-subsidization in the 2021 Rider T rate related to the over or under-recovery of Rider T revenue in 2020 in the south and north, respectively. More specifically, ATCO Gas identified that the cross-subsidization in the Low-Use rate is primarily due to an undercollection of Low-Use Rider T revenue in the north and an overcollection of Low-Use Rider T revenue in the south in 2020. The forecast versus actual Rider T revenue differences in the north and south were in opposite directions, and when these differences were combined, there was a higher rate in the north and a lower rate in the south. This resulted in more cross-subsidization.

For the Low-Use rate group, the January-February 2021 data showed an overcollection in the north and an undercollection in the south. However, ATCO Gas submitted that there was an overall undercollection of Rider T revenue in both the north and south in 2021. 2021 data showed a lower degree of cross-subsidization. If ATCO Gas excluded the true-ups of over- or undercollected amounts in 2020, the level of cross-subsidization was within the range that had been historically seen. ATCO Gas provided a revised version of the cross-subsidization analysis, which excluded the 2020 over- or undercollection. This analysis concluded that a residential customer in the north would see a $2.40 increase in their annual bill (as compared to the bill based on the province-wide Rider T rate), and a typical residential customer in the south would see a $2.46 decrease in their annual bill.

ATCO Gas submitted that continuing to use a province-wide rate was still in the public interest. A province-wide rate simplified the rate design process, and ATCO Gas noted that the NGTL rate paid by ATCO Gas was the same for both north and south service. Absent the one-time factors related to the 2020 forecast, the level of cross-subsidization continued to remain low and within the historical range seen since the province-wide rate methodology was adopted in 2014.

The AUC found the analysis and rationale for the high cross-subsidization levels provided by ATCO Gas to be reasonable. Data prior to 2020 does not show cross-subsidization levels significant enough to justify separate rates for north and south. The AUC considered the data concerning 2020 to be an outlier. The AUC noted it would continue to monitor the level of cross-subsidization in future Rider T applications and will continue to consider the need for separate north and south rates. For the time being, and given that the January and February 2021 data show the same minimal cross-subsidization trend as years prior to 2020, the AUC accepted the continued use of province-wide Rider T rates.

ATCO Gas was directed to track its Rider T cross-subsidization between north and south customers. The AUC also directed that, if in ATCO Gas's next Rider T application the subsidy between a typical residential customer in the north and south exceeds the $4.16 annual amount approved in Decision 21248-D01-2016, ATCO Gas is to provide a detailed analysis of factors that contributed to the level of cross-subsidization, using the same analysis completed for this application.

Rider T Rates and Bill Impacts

ATCO Gas stated that the total annual charges for residential customers in the north service territory that utilizes 115 GJ annually would see an increase to $839 from $825. A similar residential customer in the south service territory would see an increase to $799 from $785. ATCO Gas stated that the applied-for 2020 Rider T rate changes are reasonable and would not result in undue rate shock compared to existing distribution rates.

The AUC was satisfied that ATCO Gas had provided accurate and detailed calculations in the application and that ATCO Gas had used the correct billing determinants. The AUC noted that the updated 2021 Rider T leads to an increase in rates for the Low-Use, the Mid-Use and the High-Use Rate groups. Considering the flow-through nature of Rider T charges, the fact that they are relatively low, and the fact that the greatest estimated bill change is 3.5 per cent, the AUC found that the estimated rate impact of the proposed Rider T, to be implemented May 1, 2021 is reasonable for all rate classes.

Effective May 1, 2021, the AUC approved, for Low-Use customers, Mid-Use customers, High-Use customers and ATA customers, rates of $1.125 per gigajoule ("GJ"), $1.106 per GJ, $0.259 per day of GJ demand and $1.125 per GJ, respectively.

Aura Power Renewables Ltd. Killarney Lake Solar Project, **AUC Decision 26286-D01-2021**
Facilities - Solar Power

In this decision, the AUC approved the applications from Aura Power Renewables Ltd. ("Aura Power") to construct and operate a 22.5-megawatt ("MW") solar power plant, designated as the Killarney Lake Solar Project, located in the Municipal District of Wainright No. 61, and to connect the Project to FortisAlberta Inc.'s 25-kilovolt distribution system (the "Project").

<u>Applications</u>

The Project would consist of approximately 48,152 solar photovoltaic modules on a single-axis tracking system, including up to six inverters rated at up to 1,500 volts each. The Project would include internal access roads, cabling, switchgear, transformers and other electrical-related equipment and would be located on 160 acres of private agriculture land.

Aura Power's application included a participant involvement program, a noise impact assessment and a solar glare assessment that raised no issues. The application also included a *Historical Resources Act* approval, a renewable energy referral report issued by Alberta Environment and Parks Wildlife Management and an environmental evaluation report. These reports concluded that the Project would cause a low risk to wildlife and wildlife habitat and that any potential adverse effect of the Project can be effectively mitigated.

Following information requests from the AUC, Aura Power confirmed that it would implement a site-specific seeding and vegetation control plan prior to construction and during the operation of the Project to reduce overgrowth and, ultimately, the risk related to fire. It also confirmed that it would develop a site-specific emergency response plan in collaboration with local fire and emergency medical services staff, which would be available three months prior to construction. Further, in response to the information requests, Aura Power confirmed that the operator of the Project would periodically evaluate decommissioning costs and compare that value to the salvage value of the facility. If it is determined that the decommissioning costs exceed the salvage value, the operator will arrange to have funds held in escrow to cover the difference.

<u>Findings</u>

The AUC was satisfied that the application met the applicable information requirements and that a participant involvement program was conducted in accordance with Rule 007.

As Aura Power had not finalized the selection of equipment for the Project, the AUC imposed the following as a condition of approval:

> a) Once Aura has made its final selection of equipment for the Project, it must file a letter with the AUC that identifies the make, model, and quantity of the equipment and, if the equipment layout has changed, provide an updated site plan. This letter must also confirm that the finalized design of the Project will not increase the land, noise, glare or environmental impacts beyond the levels approved in this decision. This letter is to be filed no later than one month before construction is scheduled to begin.

The AUC was satisfied by the noise impact assessment submitted by Aura Power. Aura Power also submitted a solar glare assessment conducted by Green Cat Renewables Canada Corporation ("Green Cat"). In the solar glare assessment, a viewing angle of plus/minus 15 degrees was applied to model the transportation routes. In response to an information request by the AUC, a more conservative viewing angle of plus/minus 25 degrees was applied. In this scenario, the Project was predicted to result in up to 2,773 minutes of yellow solar glare per year at Township Road 420/415A for a scenario that assumed a backtracking angle of five degrees. In addition, Green Cat predicted that Township Road 420/415A would experience zero solar glare from the Project for all other modeled scenarios, and other glare receptors would experience zero solar glare from the Project for all the scenarios.

The AUC accepted Green Cat's predictions for the Project solar glare and its explanation that the actual solar glare expected along Township Road 420/415A would be less than the predicted duration as vehicle operators travel past the Project. The AUC noted that Green Cat's prediction results for the Project solar glare were premised on the use of an anti-reflective coating applied to the Project solar panels and were dependent on the backtracking angles of the Project solar panels.

The AUC noted that there are no public safety standards or regulations associated with solar glare that apply to the Project. The AUC expects that Aura Power will address any glare issues associated with the Project in a timely manner. In addition to the condition noted above, the AUC imposed the following conditions of approval:

> b) Aura shall use anti-reflective coating on the Project solar panels.
>
> c) Aura shall provide an update to the AUC regarding the final backtracking design specifying the final backtracking angle(s) that the Project solar panels will use during backtracking periods, and confirm that the final backtracking design will not result in increases to the solar glare impacts beyond those predicted in the solar glare assessment. This update may be part of the letter confirming the final Project design. The update is to be filed no later than one month before construction is scheduled to begin.
>
> d) Aura shall file a report detailing any complaints or concerns it receives or is made aware of regarding solar glare from the Project during its first year of operation, as well as Aura's response to the complaints or concerns. Aura shall file this report no later than 13 months after the Project becomes operational.

Further, as Aura Power had not finalized its conservation and reclamation plan and monitoring program for the Project, the AUC, as a condition for approval, required that Aura Power submit a copy of its finalized conservation and reclamation plan and monitoring program at least 60 days prior to the start of construction.

Finally, as the Project is a solar Project, it is subject to Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants,* the AUC imposed, as a condition of approval, that Aura Power submits an annual post-construction monitoring survey report to Alberta Environment and Parks ("AEP") and the AUC within 13 months of the Project becoming operational, and on or before the same date every subsequent year for which AEP requires surveys.

***Balancing Pool Application for Orders Permitting the Sharing of Records Not Available to the Public Between the Balancing Pool, URICA Energy Real Time Ltd. and Small Scale Power Producers,* AUC Decision 26308-D01-2021**

Market Oversight and Enforcement - FEOC

In this decision, the AUC approved the application from the Balancing Pool, for the preferential sharing of records pertaining to the electricity and ancillary services markets that are not available to the public between the Balancing Pool, URICA Energy Real Time Ltd. ("URICA"), Innisfail Solar Corporation ("Innisfail Solar"), Elemental Energy Inc. ("EEI") and Elemental Energy Renewables Inc. ("EERI").

The Balancing Pool had brought an application under Section 3 of the *Fair, Efficient and Open Competition Regulation* ("FEOC Regulation") for either orders to permit the preferential sharing of records that are not available to the public between the Balancing Pool, URICA and small scale power producers for which the Balancing Pool is acting as the electricity market participant or a determination that orders are not required in these cases.

Discussion of Issues and AUC Findings

Requirement for Individual Orders

Under Section 7 of the *Small Scale Generation Regulation*, the Balancing Pool has a statutory obligation to act as the electricity market participant on behalf of a small scale power producer, unless the owner of the qualified small scale generating unit requests otherwise.

The Balancing Pool explained that it does not have adequate personnel or the resources to accept energy or ancillary services dispatch orders in order to manage the output of small scale power producers in the Alberta energy or ancillary services markets on a 24-hour basis as required of an electricity market participant. To meet its obligation, the Balancing Pool entered into commercial arrangements with URICA, which provides a 24-hour real-time dispatch-desk service to clients for operational energy-market services, ancillary services, dispatch-down services and energy restatements for events at generators as required by the ISO rules. These arrangements necessitate that the Balancing Pool share records, including offer information not available to the public, for small scale power producers relating to the dispatch of electricity services with URICA.

As the Balancing Pool must act as the market participant for a small scale power producer, the AUC found that the exemption of Section 3(2)(e) of the *FEOC Regulation* is applicable. Accordingly, there was no need for an AUC order permitting the sharing of records not available to the public, as the Balancing Pool is an electricity market participant who is required to share the records with the small scale power producer according to the *Small Scale Generation Regulation.* However, this exception does not apply between URICA and the small scale power producers.

The AUC found that subsection 3(3) of the *FEOC Regulation* would support the request from the Balancing Pool for the issuance of a master order. However, the AUC noted that it preferred to issue preferential sharing of records orders for each small scale generating unit.

Provided the record-sharing arrangements with small scale power producers are approved, the AUC would issue separate orders for each small scale generating unit. If the Balancing Pool and the Market Surveillance Administrator ("MSA") would prefer a specific form of order, they may draft one that is mutually agreeable, and the Balancing Pool may provide it with the next small scale power producer preferential sharing of records application.

Finally, the AUC agreed with the MSA that small scale power producers with a capacity of 5 MW or less do not require an information-sharing order, as they will not be submitting offers into the electricity market.

Innisfail Solar Corporation

The Balancing Pool advised that it will be acting as the market participant for Innisfail Solar regarding Innisfail Solar Project ("INF1"), which had been qualified as a small scale generating unit. Innisfail Solar is owned by EEI, and EERI is the asset and project manager of INF1. The Balancing Pool requested an order, if necessary, granting the sharing of non-public records between the Balancing Pool, URICA, Innisfail Solar, EEI and EERI.

AUC Findings

Subsection 3(3) of the *FEOC Regulation* authorizes the AUC to issue an order permitting the sharing of records on any terms and conditions that the AUC considered appropriate, provided that certain requirements were satisfied. The AUC found that those requirements were met.

The AUC was satisfied that the applicants had demonstrated that the sharing of records was reasonably necessary for the Balancing Pool to carry out its business on behalf of Innisfail Solar. It was further satisfied that the subject records would not be used contrary to the fair, efficient and openly competitive operation of the Alberta electricity market, including the conduct referred to in Section 2 of the *FEOC Regulation* and that the applicants would conduct themselves in a manner that would support the fair, efficient and openly competitive operation of the market. The AUC also found that the offer control limit of the entities was less than 30 per cent, as required by subsection 5(5) of *FEOC Regulation*. The AUC also noted that the MSA supported the application.

The AUC was prepared to issue an order allowing the Balancing Pool, Innisfail Solar, EEI and EERI to share records not available to the public with URICA, subject to some terms and conditions.

The AUC noted that, as the Balancing Pool will now be acting as the market participant for Innisfail Solar, the arrangements for the sharing of records, between Innisfail Solar, EEI, EERI and URICA, approved in Decision 25438-D01-2020, would be terminated concurrent with the approval of this application.

Commission-Directed Examination of Distribution Facility Owner Payments Under the Independent System Operator Tariff Customer Contribution Policy, **AUC Decision 26061-D01-2021**
Rates - Electricity

In Decision 22942-D02-2019, which addressed the Alberta Electric System Operator's ("AESO") 2018 tariff, the AUC approved changes to the recovery and treatment of contributions in aid of construction ("CIAC" or "AESO Customer Contributions") paid by distribution facility owners ("DFOs") to the AESO. These findings were varied in Decision 24932-D01-2020. In its variance decision, the AUC advised that it would further examine the treatment and recovery of these contributions in a further proceeding. It undertook that examination in this proceeding.

In this decision, the AUC determined that:

(a) The legislative framework applicable to electric utilities supports the payment of customer contributions to the AESO as part of the AESO's tariff.

(b) No changes to the AESO's customer contribution policy currently set out in the approved AESO tariff were directed.

(c) The legislative framework applicable to electric utilities permits the current DFO tariff recovery mechanism of AESO customer contribution payments made by a DFO.

(d) The current DFO tariff recovery mechanism applicable to AESO customer contributions fails to provide effective price signals to incent the end-use customers to choose the most economical connection solution. To better achieve the objectives of the AESO customer contribution policy:

  (i) DFOs will no longer be permitted to earn a return (i.e., return-on-equity component) on any AESO customer contribution payments; and

  (ii) to the extent possible, customer contributions are to be flowed through to the DFO customer that is requesting the new connection.

(e) A revised accounting mechanism for the recovery of future AESO customer contribution payments in a DFO tariff will be examined in a further proceeding. DFOs are directed to file one or more proposal(s) for a revised accounting treatment for the recovery of future AESO customer contributions that achieve the objectives set out in this decision by May 31, 2021.

(f) (Changes to the DFOs' tariff recovery mechanism are to be applied on a prospective basis to new AESO customer contributions, effective as of the date of this decision. AESO customer contributions made by DFOs for new projects following the date of this decision are directed to be tracked as placeholder amounts and will be accounted for according to the revised accounting treatment approved by the Commission.

(g) AESO customer contributions made by DFOs prior to the date of this decision shall continue to be treated according to the current DFO tariff recovery mechanism that allows the contribution costs to be capitalized and included in the rate base until those contribution amounts have been fully depreciated.

(h) Alternative AESO customer contribution refund proposals, including the one proposed by AltaLink, that allow a transmission facility owner ("TFO") to earn a return on an AESO customer contribution, also fail to provide an effective price signal and were not approved.

Is the Current Treatment of Customer Contributions Supported by the Legislative Framework?

The AESO defines a construction contribution as the financial CIAC in excess of any available maximum local investment by the AESO in system costs that a market participant must pay for the construction and associated costs of transmission facilities required to provide system access service ("SAS"). Under its current tariff, the AESO requires contributions from (a) DFOs; (b) customers directly connected to the transmission system; (c) a designated industrial system; and (d) the City of Medicine Hat. The focus of this decision is on the customer contributions paid by DFOs.

After reviewing the legislative provisions and the historical treatment of customer contributions, the AUC concluded that the legislative framework is aligned with and supports the inclusion and operation of a customer contribution policy within the AESO tariff.

DFO Recovery of AESO Customer Contributions

The AUC then examined how DFOs (specifically Fortis) had been recovering these contribution costs and examined the treatment of AESO customer contribution amounts prior to 2013 under cost of service ratemaking and subsequently under Performance Based Regulation ("PBR") plans for DFO tariffs.

The AUC noted that it continues to support the principles it had previously identified as the foundation for a customer contribution policy, the most important of which is the establishment of an effective price signal for the siting of connection facilities. In Decision 2012-362, the Commission found that the AESO's customer contribution policy should "exert an economic discipline on siting decisions by sending price signals, reflective of the AESO's economics, to connecting customers." Further, customer contributions are intended to balance the economic effects of connecting a new customer between existing customers and the new customer.

A CIAC is required to be made by a connecting customer when the construction and associated costs of transmission facilities required to provide SAS exceed the available investment by the AESO (the maximum investment level). Connecting customers that have to bear the project costs above the AESO maximum investment levels by way of a CIAC are incented to (i) request the most economical connection facilities and service requirements that meet their needs; and (ii) take into account proximity to the existing or planned transmission system when considering alternative locations for their load to be served. In turn, these contribution amounts offset the investments made by the TFO (with a TFO only investing up to the maximum investment level and therefore only receiving a return of, and on, that investment). As a result, existing customers do not unduly subsidize the construction of new facilities.

However, the AUC noted that, unlike Direct Connect customers who bear the costs of the connection directly, DFOs could pass the costs of the CIAC on to distribution ratepayers. From a regulatory perspective, the recovery of an AESO customer contribution is indistinguishable from the way in which the DFO recovers its capital assets and puts the invested contributions under the same incentives.

The AUC had previously commented on the incentives associated with the cost of service regulation:

> … under cost of service regulation, since the company earns a profit on the equity in its rate base, there is an incentive to choose spending money on capital assets, on which a return can be earned, over spending on maintenance, for example, on which a return is not earned. In addition, there is no incentive to minimize the costs of capital assets. The more that is spent and included in the rate base, the more return that can be earned.

In Decision 20414-D01-2016, the AUC recognized that similar incentives were also present under the capital tracker mechanism included in the 2013-2017 PBR plans regarding capital expenditures (including the AESO customer contributions). Capital trackers were administered in a manner similar to traditional cost of service regulation (i.e., relying on prudence reviews to establish the necessary level of capital investment) and had the unintended effect of placing a considerable amount of capital outside of the incentive-enhancing I-X mechanism.

The AUC considered that there is a general incentive for DFOs to increase the amount of AESO customer contributions to grow rate base, which is exacerbated by the fact that a DFO has a degree of influence on transmission project requirements, associated costs, and therefore AESO customer contribution amounts. The current DFO tariff recovery mechanism applicable to AESO customer contribution amounts, therefore, fails to provide effective price signals intended to incent the end-use customers to choose the most economical connection solution.

The AUC noted that first, the DFO is not generally flowing the costs of the AESO customer contribution amounts to the end-use customers that trigger the need for new connection assets. As a result, the costs of the AESO customer contributions associated with the connections are socialized across all DFO customers. This mutes the price signal on siting decisions since the customer or customers that caused the need for a new connection do not directly pay their share of the AESO customer contribution. Conversely, when the AESO customer contributions are passed through to an end-use customer of a DFO or are paid by a Direct Connect customer, the intended price signal to impose economic discipline on siting decisions operates properly.

Second, the DFO is able to earn a return on its invested AESO customer contribution amounts. As a result, the intended price signal is at best distorted or muted and is likely absent. In fact, what was intended to be a price signal is converted to a revenue signal to a DFO. The AUC considered that the tariff recovery mechanism applicable to AESO customer contributions could create an incentive for Fortis, as a pure-play DFO, to prefer a transmission solution over a distribution solution because it would need to manage and operate the assets associated with a distribution solution and bear all of the attendant ownership risks when it receives the same rate of return on the investment in either case.

The AUC also found, however, that allowing a TFO to earn the return on the AESO customer contributions paid by a DFO through a refund, as proposed by AltaLink, would also mute the price signal to “right-size” the capital cost of new facilities. AltaLink’s proposal would allow it to earn a return on “gross” rate base rather than on rate base net of contributions, thereby nullifying the price signal to customers, which is intended to bring discipline to the cost of new facilities and result in a prudent investment. Consequently, the AUC found that it would not be in the public interest for either a DFO or a TFO to earn a return on AESO customer contributions.

The AUC found that it is in the public interest to address the issues arising from the revenue signal identified in this decision and to better achieve the underlying objective of the AESO customer contribution policy; namely, to send price signals to connecting customers that are considering alternatives for siting their interconnecting loads. To achieve this objective, it is necessary to (i) remove the profit element (i.e., return-on-equity component) earned on any AESO customer contribution payments DFOs make; and (ii) to the extent possible, flow these contributions through to the DFO customer that is choosing between a transmission or distribution connection.

By removing the profit element, the conflict between the incentive for a DFO to increase its rate base and the requirement to consider the least cost technical solution to meet customer connection requirements is removed. Second, by flowing through the AESO customer contributions, where possible, to the specific customers that require the connection and, therefore, the additional investment, the price signal is imposed on the customer, in terms of decisions both with respect to siting and to the nature and size of facilities required.

The AUC noted that the scope of this proceeding did not extend to establishing a new DFO tariff recovery mechanism applicable to AESO customer contributions. The AUC will commence a process to examine the tariff mechanism for the recovery of future AESO customer contributions within the DFO tariff that takes into account the findings of the Commission herein.

The AUC directed the DFOs to file a proposal or proposals for a revised regulatory accounting treatment of their subsequent AESO customer contributions by May 31, 2021, to reflect the findings in the present decision. The AUC found that a change to the DFO tariff recovery mechanism will be applied on a prospective basis to new AESO customer contributions, effective as of the date of this decision. The DFOs were directed to track all subsequent AESO customer contribution payments as placeholders. The tariff recovery mechanism currently in effect for AESO customer contributions made prior to the date of this decision shall continue to be in effect until these costs are fully depreciated.

***ENMAX Corporation Inc. and Calgary District Heating Inc. Applications for Disposition of the Downtown District Energy Centre and Transfer of the Combined Heat and Power Generating Unit,* AUC Decision 26163-D01-2021**

Public Utilities Act - Ordinary Course of Business

In this decision, the AUC approved the disposition by ENMAX Corporation of the Downtown District Energy Centre ("DDEC") and the transfer of related approvals from ENMAX Independent Energy Solutions Inc. ("EIES") to Calgary District Heating Inc. ("CDHI").

<u>Introduction and Process</u>

ENMAX Corporation ("ENMAX") is the owner and operator of the DDEC, which provides district energy to municipal, commercial and residential buildings in downtown Calgary. The DDEC contains a 3.3 megawatt ("MW") natural gas-fueled combined heat and power generating unit ("CHP unit") owned by EIES, a subsidiary of ENMAX.

<u>Application to Dispose of the DDEC</u>

Background

ENMAX is a designated owner of a public utility for the purposes of sections 101 and 102 of the *Public Utilities Act* ("*PUA*") pursuant to Section 1(1) of the *Public Utilities Designation Regulation*. ENMAX owns and operates the DDEC, which is itself a public utility within the meaning of Section 1(i) of the *PUA*. ENMAX, wholly owned by the City of Calgary, operates the DDEC on an unregulated basis pursuant to Section 78(2) of the *PUA*. Section 78(2) exempts a public utility owned or operated by a municipality from the application of Part 2 of the *PUA* unless the public utility is brought under the act by a bylaw of the municipality.

CDHI is a wholly-owned subsidiary of Atlantica Sustainable Infrastructure plc., which owns and operates a portfolio of assets that includes electricity generation, storage and transmission facilities in various jurisdictions. ENMAX filed a letter provided by CDHI confirming that CDHI supports ENMAX's applications before the AUC. CDHI also confirmed that it understood that it had agreed to purchase a public utility and would accept full regulatory responsibility for the DDEC under Part 2 of the *PUA*. CDHI acknowledged that under its ownership, the DDEC would no longer be eligible for the exemption in Section 78(2) of the *PUA.* However, CDHI stated that it intended to bring an application before the AUC in the future seeking exemptions from certain provisions of the *PUA* to obtain regulatory treatment consistent with complaint-based regulation.

Approval of Dispositions Outside of the Ordinary Course of Business

Section 101(2)(d)(i) of the *PUA* requires the AUC to approve the sale or disposition of property by the owner of a designated public utility when made outside of the ordinary course of business.

The AUC noted that the DDEC is the only district energy facility operated by ENMAX and that that the sale of an asset that itself constitutes a public utility is a relatively unusual occurrence. The AUC, therefore, agreed with ENMAX's view that the sale of the DDEC is outside of the ordinary course of ENMAX's business and requires approval under Section 101(2)(d)(i) of the *PUA.*

AUC Jurisdiction to Grant Exemptions from the Approval Provision

Under Section 101(4) of the *PUA*, the AUC has jurisdiction to grant an exemption from the requirement to obtain approval under Section 101(2) regarding a specific transaction or class of transactions. Among other factors, when considering whether to grant an exemption, the AUC is required to consider if the exemption would undermine the ability of a public utility to provide safe and reliable service at just and reasonable rates.

ATCO Gas argued that the operation of the DDEC within its service area has policy implications for the utility system that had not been addressed. ATCO Gas intervened, in part, to assert that the unique characteristics of the transaction warrant a broader review than the AUC would ordinarily apply to the sale of an asset. The AUC accepted that the circumstances of this transaction are unique, particularly as it constitutes the sale of a public utility to an owner that is a new entrant to the Alberta utility sector. In these circumstances, and given the concerns cited by ATCO Gas, the AUC considered it prudent to review the transaction to ensure that any potential harm arising from the disposition of the DDEC is understood and considered. The AUC therefore did not exercise its discretion to exempt the transaction from the application of Section 101(2) of the *PUA*.

Evaluation Under the No-Harm Test

In its consideration regarding the approval of a disposition application that is outside the ordinary course of business under Section 101 (2) of the *PUA,* the AUC and its predecessor have traditionally applied a "no-harm" test. This test considers the disposition in the context of both potential financial impacts and service level impacts, in terms of both quantity and quality, to customers.

The "no-harm" test has been reviewed in several board, AUC and court decisions. The AUC has generally applied the no-harm test to consider potential harm to customers served by the property that is the subject of a proposed transaction, as well as customers of any regulated affiliate of a public utility that is a party to the transaction. In this proceeding, the AUC requested that parties address the question of which customers should be considered if the AUC were to apply the no-harm test with respect to customers of the DDEC as well as customers that receive regulated utility service from ENMAX Power Corporation ("EPC"), which is a subsidiary of ENMAX.

ATCO Gas submitted that the AUC should also consider harm to ATCO Gas' past, present and future customers, arguing that the existence and potential expansion of DDEC service may contribute to upward pressure on the rates paid by ATCO Gas customers. Further, ATCO Gas submitted that beyond the traditional no-harm test, the AUC's review of the transaction should address the DDEC's history and future operations. ATCO Gas argued that the AUC should take a broad view of the transaction given the unique circumstances of a municipally-owned entity disposing of a public utility to a non-municipal owner and the fact that there is uncertainty around the future regulatory treatment of the DDEC given CDHI's intent to seek exemptions to certain provisions of the *PUA*.

Should the disposition be approved, ATCO Gas requested that the AUC impose conditions on CDHI regarding disclosure of the rates paid by DDEC customers and any plans to expand DDEC service. ATCO Gas also requested that the AUC's approval of the disposition be subject to a condition that any change or expansion to DDEC service would require the approval of the AUC.

The AUC was not satisfied that the circumstances of this proceeding were sufficiently unique to warrant a departure from the well-established no-harm test, which has evolved over time to reflect the AUC's statutory mandate and which has been acknowledged by both the Court of Appeal and Supreme Court of Canada. The AUC acknowledged the concerns raised by ATCO Gas relating to potential harm to its customers arising from the past and current operation of the DDEC, as well as harm that may arise if DDEC service is expanded in the future. However, the AUC found that ATCO Gas' concerns are speculative and that ATCO Gas failed to establish any connection between these concerns and the transaction that is the subject of this proceeding.

The AUC questioned the relevance of the impacts to ATCO Gas customers for the AUC's application of the no-harm test. In any event, the AUC agreed with ENMAX that there was no evidence in this proceeding to suggest that ATCO Gas or its customers would suffer any incremental harm if the DDEC was owned by CDHI. The impacts asserted by ATCO Gas were speculative and related to the existence of the DDEC rather than its disposition.

The AUC found that the evidence before it in this proceeding demonstrated that there would be no impacts on the safety or quality of utility service because of the transaction. The AUC was satisfied that CDHI, through its parent company, has sufficient expertise to provide the same level and quality of service to DDEC customers as they currently experience under ENMAX. The AUC also accepted that there would be no impacts to regulated customers of EPC, as the DDEC business has been operated by ENMAX on a standalone basis, separate and apart from the core regulated utility function carried out by EPC. The AUC also found that approval of the disposition would not result in any financial harm to the customers of the DDEC or EPC. The AUC noted that the transaction costs would be borne by ENMAX and would not be recovered from ratepayers.

Application to Transfer Power Plant Approval and Connection Order

The DDEC contains a 3.3 MW natural gas-fueled CHP unit, which operates pursuant to Power Plant Approval 23243-D04-2018 and is connected to the Alberta Interconnected Electric System ("AIES") via EPC's 25-kilovolt distribution system pursuant to Connection Order 26110-D02-2020. The power plant approval and connection order are held by EIES. ENMAX, on behalf of EIES, requested that the AUC authorize the transfer of Power Plant Approval 23243-D01-2018 and Connection Order 26110-D02-2020 from EIES to CDHI to reflect the change of ownership that would be affected by the transaction.

The AUC approved the transfer of the power plant approval and connection order to CDHI. The AUC noted it would issue a new power plant approval and connection order upon receipt of written confirmation that the ownership transfer was completed and, accordingly, required that this information be filed no more than seven days after the transaction closed by ENMAX or CDHI. CDHI confirmed that upon the transaction closing, it would become the owner of a public utility and will accept full regulatory responsibility for the DDEC under Part 2 of the *PUA*. The AUC considers this commitment by CDHI to include sections 101, 102 and 109 of the *PUA*. Therefore, effective from the closing of the transaction until the AUC declares otherwise, the AUC directed CDHI to conduct itself as though it were a designated owner of a public utility under the *Public Utilities Designation Regulation*.

***EPCOR Distribution & Transmission Inc. Summerside 657S Substation Alteration,* AUC Decision 26320-D01-2021**

Electricity - Facilities

In this decision, the AUC approved an application from EPCOR Distribution & Transmission Inc. ("EDTI") to alter and operate the Summerside 657S Substation ("the Substation").

As the owner of the Substation, EDTI applied to amend the Substation to serve forecast increase in residential and industrial load in the south Edmonton area following a system access service request from a market participant. The need for transmission development had been approved by the Alberta Electric System Operator ("AESO"). EDTI applied to meet the increased need by adding one new 240/25-kilovolt ("kV"), 45/60/75-megavolt ampere ("MVA") transformer, one new 240-kV circuit breaker, six new 25-kV circuit breakers and associated substation equipment.

EDTI applied to install upgrades beyond the four 25-kV breakers needed to meet the market participant's request for reasons of economies of scale, equipment availability, consistency with standard practice, and to accommodate future connections for growth that had already been contemplated. The market participant would bear the cost of the entire project.

No issues were raised in meeting all requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* and Rule 012: *Noise Control.* The AUC determined that approval of the project was in the public interest. The application was approved pursuant to sections 14, 15, and 19 of the *Hydro and Electric Energy Act*. As the facility is located in the Edmonton transportation and utility corridor, the AUC noted it could not issue a permit and licence for construction and operation without written consent of the Minister of Infrastructure. The licence and permit would therefore be issued once the consent is given, as required by the *Edmonton Restricted Development Area Regulations.*

Signalta Resources Limited High River Peaking Power Plant, **AUC Decision 26127-D01-2021**
Facilities - Peaking Power Plant

In this decision, the AUC approved the application from Signalta Resources Limited ("Signalta") to construct and operate a power plant, designated as the High River Peaking Power Plant, and connect the power plant, located in the High River area, to the Alberta Interconnected Electric System ("AIES") (the "Project").

Discussion

Signalta applied for approval to construct and operate a 19.95-megawatt ("MW") natural gas-fired power plant, pursuant to Section 11 of the *Hydro and Electric Energy Act* ("*HEEA*"). Signalta proposed the Project as a cost-effective source of reliable natural gas-fueled electricity supply. The Project would contribute as a new source of electricity and ancillary services operating primarily during periods of high electrical demand and power pricing. Signalta stated that the dispatchable and fast responding facility would offset renewable generation and assist in the reduction of grid supply volatility.

Signalta proposed to install the Project in three stages. The first stage would include eight natural gas generators with a combined generation capability of up to 12 MW. Stages two and three would each consist of four natural gas generators with a combined generation capability of up to 5.6 MW, per stage. Signalta anticipated stages two and three would proceed within two years of the first stage. It also indicated that the combined total output would be limited to 19.95 MW via operating procedures and power flow controls. The Project's required sweet natural gas fuel would be sourced from a new ATCO Energy Services tap from an existing ATCO Gas pipeline.

Signalta proposed to construct the Project on a pre-existing oil and gas lease located approximately 0.9 kilometers north of High River, in an area designated as an industrial corridor. Signalta also indicated that it would take over the end-of-life obligations for two abandoned natural gas wells located on the site.

Construction is scheduled to start immediately after all approvals have been received, with the in-service date of the final stage being August 2023.

Signalta applied to connect each stage of the proposed Project to the AIES via three existing FortisAlberta Inc. 25-kilovolt distribution lines located on or near the Project site. Signalta provided a letter of non-objection regarding the proposed Project from FortisAlberta Inc and noted that the AESO had been informed of the Project.

Findings

Signalta's environmental impacts would be largely confined to environmental impacts to air quality and emissions. In response to an information request, Signalta explained that because the proposed Project is a peaking power plant, the facility will operate much less than a continuous duty base load power plant. The Project's total emissions per year would, as a result, be 70 to 86 per cent less as a consequence. Given Signalta's assertion that the Project will not result in any major impacts to the environment and the existence of the two abandoned wellsites, the AUC agreed that the environmental impacts would not be significant.

The AUC approved the application for the Project.

SunAlta Solar Inc. - SunAlta Solar PV1 Power, AUC Decision 25951-D01-2021

Solar Energy Facility Application - Environmental and Visual Affects - Property Values

In this decision, the AUC approved applications from SunAlta Solar Inc. ("SunAlta") to construct and operate a power plant designated as the SunAlta Solar PV1 Project, and to connect the Project to FortisAlberta Inc.'s 25-kilovolt electric distribution system.

Application and Project Details

SunAlta filed applications with the AUC for approval to construct and operate a 9.25-megawatt ("MW") solar power plant designated as the SunAlta Solar PV1 Project (the "Project") and to connect the Project to FortisAlberta Inc.'s 25-kilovolt electric distribution system.

The Project would be located entirely on private lands in Newell County, approximately 14 kilometers southeast of the town of Bassano, Alberta, and interconnected to FortisAlberta Inc.'s 25-kilovolt electric distribution system. SunAlta filed a letter provided by FortisAlberta Inc. indicating that it had no concerns with the interconnection of the Project.

The AUC received a statement of intent to participate from Krista Evans. Krista Evans owns land immediately south of the Project area, which contains a dwelling approximately 360 meters south of the Project boundary. Krista Evans' concerns primarily related to environmental, health and visual effects.

Discussion and Findings

Rule 007

The AUC reviewed the applications and found that the information requirements and the requirements for a participant involvement program specified in Rule 007 were met.

Environmental and Health Effects

Krista Evans expressed concern about SunAlta's failure to identify the substances to be used in the Project and about the possibility that hazardous chemicals would be contained in Project equipment and infrastructure. The AUC acknowledged the concerns raised by Krista Evans about the potential for environmental contamination and health effects from the Project on nearby residents and livestock but found that the evidence filed in the proceeding does not support such concerns.

Regarding the environmental effects of the Project more generally, the AUC noted that the Project would be sited entirely on previously disturbed land that avoids environmentally sensitive features, and Alberta Environment and Parks ("AEP") had determined that the Project presents a low risk to wildlife and wildlife habitat. Furthermore, SunAlta had committed to implementing the mitigation measures set out in Stantec's Project-specific environmental evaluation, and those measures had been reviewed and accepted by AEP in the renewable energy referral report.

The AUC also noted that SunAlta has a conservation and reclamation plan ("C&R") plan, a stormwater management plan, and an emergency response plan in place to address any environmental issues related to construction, operation, reclamation, and emergencies during the Project life cycle.

The AUC accepted the commitments made by SunAlta in its C&R plan as these commitments are consistent with the requirements of the *Environmental Protection and Enhancement Act* and the *C&R Directive*. Based on the C&R plan, the Project reclamation will meet equivalent land capability at the end of the Project life cycle, as determined by reclamation criteria for the desired end land use. In addition, SunAlta would obtain a reclamation certificate from AEP before decommissioning the Project. As such, the AUC noted that it expects that during the reclamation stage, the Project will be decommissioned properly, and Project materials will be disposed of responsibly.

Having regard to the foregoing, the AUC was satisfied that with the implementation of and adherence to the mitigation measures identified, the C&R plan, the stormwater management plan, and the emergency response plan, the Project is unlikely to result in significant environmental effects and any potential adverse environmental effects from the Project will be adequately addressed.

Subsection 3(3) of *Rule 033* requires approval holders to submit to AEP and the AUC annual post-construction monitoring survey reports. Consequently, the AUC imposed the following condition of approval:

> a) SunAlta shall submit an annual post-construction monitoring survey report to AEP and the AUC within 13 months of the Project becoming operational and on or before the same date every subsequent year for which AEP requires surveys.

Solar Glare and Noise

The AUC accepted the report by Green Cat Renewables Canada Corporation and its conclusion that: nearby dwellings and Range Road 175 would not experience glare from the Project; the railway, Range Road 174 and Township Road 202 would experience some glare from the Project; and that glare from the Project would have low potential to create hazardous conditions at receptors.

The AUC found that there were no present public safety standards or regulations associated with solar glare that apply to the Project. The AUC did, however note its expectation that any glare issues associated with the project will be addressed by SunAlta in a timely manner. The AUC imposed the following conditions of approval:

> b) SunAlta shall use an anti-reflective coating on the Project solar panels.
>
> c) SunAlta shall file a report detailing any complaints or concerns it receives or is made aware of regarding solar glare from the Project during its first year of operation, as well as SunAlta's response to the complaints or concerns. SunAlta shall file this report no later than 13 months after the Project becomes operational.

With respect to noise impacts, the AUC found that the noise impact assessment report submitted by SunAlta met the requirements of Rule 012 and accepted the conclusion of that report that noise from the Project will comply with the permissible sound levels.

The AUC decided not to impose post-construction noise monitoring as a condition of approval because the nighttime cumulative sound level at Krista Evans' dwelling (the nearest occupied dwelling) is predicted to be 36.3 A-weighted decibels ("dBA"), which is 3.7 dBA less than the applicable nighttime permissible sound level from Rule 012 (i.e., 40 dBA). In addition, the Project noise contribution at Krista Evans' dwelling is predicted to be 19.1 dBA, which is 15.9 dBA less than the 35 dBA nighttime ambient sound level. The noise contribution from the Project is thus expected to be minimal at Krista Evans' dwelling.

The AUC noted that SunAlta did not finalize its selection of equipment for the Project. Consequently, the AUC imposed the following as a condition of approval:

> d) Once SunAlta has made its final selection of equipment for the Project, it must file a letter with the AUC that identifies the make, model, and quantity of the equipment and, if the equipment layout has changed, provide an updated site plan. This letter must also confirm that the finalized design of the Project will not increase the land, noise, glare or environmental impacts beyond the levels approved in this decision. This letter is to be filed no later than one month before construction is scheduled to begin.

Visual Effects

The AUC's evaluation of visual effects from the Project focused on Krista Evans' dwelling rather than unoccupied land or nearby transportation routes. Krista Evans expressed concern about the visual effects of the Project. She stated that it was her intention to return to her property to raise her family, but since the announcement of the Project, she no longer wished to live there "because of the visual aspects I [she] would be forced to endure on a daily basis."

The AUC acknowledged Krista Evans' concerns about the visual effects of the Project. However, based on the very limited evidence available, the AUC was not persuaded that the Project would have an adverse visual effect on Krista Evans' dwelling, such that visual abatement as a condition of approval is warranted.

In addition, the AUC noted that the proposed Project design has incorporated feedback provided by an industrial stakeholder during the participant involvement program. As a result of this feedback, some solar arrays initially located close to the south property line (i.e., close to Krista Evans' property) had been removed. Although these design changes were not implemented to address Krista Evans' concerns, the AUC found that they reduced the potential for visual effects from the Project on Krista Evans' property.

Property Value

The AUC had previously expressed the view that concerns over property value impacts require specialized expertise and evidence in order for the AUC to conclude that a given project will have an adverse effect on land and property values. No such evidence was filed in this proceeding.

Conclusion

The AUC noted that FortisAlberta Inc. did not express any concerns with the proposed interconnection of the Project to the Fortis Alberta Inc. distribution system, and there are no outstanding public or industry concerns related to the interconnection.

For the reasons outlined above and subject to all of the conditions listed, the AUC found that approval of the Project is in the public interest having regard to the social, economic, and other effects of the Project, including its effect on the environment.

TransAlta Corporation - Decision on Preliminary Question Application for Review of Decision 25369-D01-2020 Direct Assigned Capital Deferral Account for the Edmonton Region Project, **AUC Decision 26305-D01-2021**

Request for Review

In this decision, an AUC review panel ("Review Panel") denied TransAlta Corporation's ("TransAlta") application to review the findings in Section 3.2.10 of Decision 25369-D01-2020 (the "Decision") in which it was determined that not all of the costs incurred for the construction of transmission line 1043L-Reserve were prudently incurred. The hearing panel ("Hearing Panel") reduced the transmission line costs as well as the legal and related costs attributable to negotiating and concluding a Cooperation Agreement with the Enoch Cree Nation ("ECN").

Discussion of Issues and Review Panel Findings

The AUC Breached TransAlta's Right to Procedural Fairness

TransAlta claimed that the Hearing Panel made an error of law because the Hearing Panel disallowed costs on the basis of the finding that the parties (TransAlta and AltaLink Management Ltd., or "AML") failed to meet the consultation requirements set out in Rule 007. TransAlta pointed to the fact that no IRs or notices were provided by the Hearing Panel that would have alerted them that the Hearing Panel had a concern as to their compliance with Appendix A1 of Rule 007.TransAlta asserted that this concern would constitute a "New Issue".

The Review Panel noted that, at all times, the onus was on TransAlta and AML to demonstrate the prudence of their costs. It noted that IRs were sent to each of TransAlta, AML, and ECN and that, moreover, TransAlta and AML are sophisticated parties who understand the legislative scheme and AUC rules applicable to their operations.

The Hearing Panel determined from the record that "there is no record of communication with Enoch from a month prior to the facilities application (June 2010) to just two months before AltaLink restarted construction on the reserve (October 2011), a period of one year and four months." The Hearing Panel noted in paragraphs 112 and 113 of the Decision, the absence of any documentary evidence to support the requirement to document commitments.

The Review Panel found that not only did the Hearing Panel make known that the consultation commitments made by TransAlta to ECN were of interest, it provided several opportunities for TransAlta to provide the evidence it was relying on in support of its applied-for relief. However, TransAlta, by its own admission, had nothing further to provide in evidence. The Review Panel found that the process established provided TransAlta with a full opportunity to present its case to support the prudence of its costs.

The AUC Misinterpreted or Misapplied the Prudence Test

TransAlta argued that the Hearing Panel held that it would apply the prudence test to the Edmonton Region Project costs but then modified or ignored components of the test, thus committing an error of law. TransAlta noted that the Hearing Panel ignored evidence that multiple meetings took place between October 2011 and May 2012 and that the ECN liaison was present, thus demonstrating that they had met their commitments.

The Review Panel again noted that the onus is on the applicant to demonstrate the prudence of costs. The Hearing Panel noted a gap in evidence supplied by TransAlta for the 2011-2012 period and that it would have been reasonable for them to expect evidence "such as meeting dates beyond October 27 or action items, […] a written evidential record to support this assertion, such as emails arranging the meetings, calendar invites, meeting notes, or invoices for catering". The Hearing Panel applied the prudence test on the evidence that was provided and therefore did not commit an error of law. For this reason, the Review Panel dismissed the request for review on this ground as well.

The AUC Erred in Law in its Consideration of Rule 007, the Duty to Consult, and the Right of Way ("ROW") Agreements

TransAlta argued that the Hearing Panel erred in law by scrutinizing engagement with the ECN in the period following the facilities application through the lens and documentary requirements of Rule 007. TransAlta claimed that the purpose of Rule 007 is to guide applicants in preparing a participant involvement program and does not impose consultation on all phases of a construction project. The Review Panel disagreed with this narrow characterization of Rule 007, noting that consultation is an ongoing process. It dismissed TransAlta's request for review on this ground.

TransAlta also claimed that an error of law arose because the Hearing Panel determined the scope and content of the duty to consult based solely on Rule 007 without regard to the *Constitution Act* or notice to the Attorney General of Canada. The Review Panel found that TransAlta appeared to conflate references to consultation under Rule 007 with the Crown's duty to consult affirmed by the Supreme Court of Canada, which considers consultation and accommodation of Indigenous groups when conduct might adversely impact established or potential treaty rights. The Review Panel found that the Hearing Panel's examination of TransAlta and AML's consultation with ECN was conducted in the context of reviewing their actions for prudence, in particular with respect to their follow-up commitments. For this reason, TransAlta failed to demonstrate an error in law on these grounds.

TransAlta also claimed that the Hearing Panel overlooked its right to access the right of ways, including how the agreements circumscribe the scope and content of the duty owed by TransAlta and AML to consult with ECN. However, the Review Panel noted that the Hearing Panel reduced expenditures available for recovery due to the detrimental effect of TransAlta's failure to adhere to its commitments during the pre-construction stage, a period of 16 months. The Review Panel found that TransAlta failed to demonstrate an error on this ground.

The AUC Erred in Basing the Disallowances on the Entirety of the Cost of the Edmonton Region Project, and not the Incremental Costs of the Delays

TransAlta claimed that the Hearing Panel based its disallowance of 15 per cent on the entirety of the costs of the 1043L-Reserve portion of the Edmonton Region Project instead of on the incremental cost of the delays, and that this represents an error of law. The Review Panel found that the Decision made it evident that the Hearing Panel considered the prudent conduct of all parties during all phases of construction. Moreover, the *Electric Utilities Act* grants the AUC broad discretion in determining what costs are prudent or reasonable and does not require a line by line evaluation of each cost incurred to make its decision. Therefore, TransAlta's request on this ground was denied.

Decision

For the reasons set out above, the Review Panel found that TransAlta had not met the requirements for a review and the application was therefore dismissed.

CANADA ENERGY REGULATOR

***Campus Energy Partners Suffield LP Application for Suffield North Pipeline Tolls and Terms and Conditions of Service and Rockpoint Gas Storage Canada Ltd., Pine Cliff Energy Ltd., and Torxen Energy Ltd. Complaints Regarding Suffield Processing Limited Partnership and its General Partner 2133151 Alberta Ltd.* – CER Letter Decision RH-002-2020**

Gas - Tolls - Terms and Conditions

In this decision, the CER considered the application from Campus Energy Partners Suffield LP by its general partner Campus Energy Partners Operations Inc. ("Campus") regarding tolls and terms and conditions of service for its North Suffield Pipeline (the "Pipeline"). The CER decided the following:

- Campus may exercise its discretion and establish term-differentiated firm tolls that do not exceed $0.22/gigajoule ("GJ");
- Firm Transportation ("FT") tolls to be filed by Campus are approved as final, effective as of the date of this decision (April 7, 2021) and retroactive to the date they were made interim;
- Campus was granted the discretion to set its Interruptible Transportation ("IT") toll at market-responsive tolls of $0.32/GJ or lower;
- Interruptible preferred service ("ITp") was approved at a toll of the shipper's corresponding FT service plus $0.02;
- Interim IT tolls were made final for the period of 1 July 2019 to 30 April 2021;
- Regarding the transportation service agreement ("TSA" or "TSAs"), the CER approved modifying the existing notice period to three months, but did not approve other proposed changes; and
- The CER did not approve the proposal for shippers to pay for all costs of testing at this time, nor did the CER approve the change from testing every three months to testing every 90 days, as requested by Campus.

<u>Background</u>

In June 2019, Rockpoint Gas Storage Canada Ltd. ("Rockpoint"), Pine Cliff Energy Ltd. ("Pine Cliff"), and Torxen Energy Ltd. ("Torxen") collectively (the "Complainants") filed complaints with the CER's predecessor, the National Energy Board ("NEB"), concerning the level of tolls charged by Suffield Processing Limited Partnership ("SPLP") on the Pipeline.

In a letter dated 21 February 2020, after a pause to allow for a potential negotiated resolution, the Commission found that the Complainants raised relevant concerns as to the appropriateness of the proposed tolls and terms and conditions of service. The Commission indicated that the record before it, including Campus' limited filings in response to the Complainants, was insufficient to establish that the proposed tolls and terms and conditions of service were just and reasonable and ordered Campus to file an application for tolls and terms and conditions of service for the Pipeline.

The CER outlined some of the regulatory history of the North and South Suffield pipelines. These pipelines had been described by the original owner as a commercially at-risk pipeline and proposed market-based tolls, offering firm service terms of five to 20 years at fixed tolls. The firm service tolls incorporated a long-term incentive approach offering lower tolls for a longer-term commitment. The stated objective was to ensure the viability of the project while providing an acceptable return on investment and to provide shippers with long-term certainty. The applicant submitted that the pipelines would provide shippers with an alternative to NOVA Gas Transmission Ltd. ("NGTL").

One shipper subscribed for a large portion of the capacity on both the South and North Suffield pipelines for 20-year terms, which are nearing expiry. Other shippers also entered into contracts for smaller volumes.

The NEB approved the South and North Suffield Pipeline. It found the pipelines were required by the present and future public convenience. The NEB had found that the method of regulation was acceptable for the pipeline and did not find it necessary issue an order approving the proposed tolls and tariffs.

A transfer application from AltaGas Holdings Inc. to Campus in 2018 included a statement that the purchaser did not have existing plans to alter or implement any changes to the tolls and tariffs on the Pipelines. The TSAs with each complainant provided that tolls could only be changed once per year, with a 15 month notice period. The TSAs could be terminated with a 30-day notice. Following the transfer to Campus on February 1, 2019, Rockpoint stated that it had entered into a tie-in agreement with AltaGas based on terms of its existing TSA and in reliance on representations made in the transfer application. The agreement allowed Rockpoint to construct a pipeline lateral associated with one of Rockpoint's gas storage facilities into an AltaGas pipeline associated with the Pipeline.

On 11 March 2019, Campus gave notice of a toll change to firm and interruptible service and the TSA. On 22 March 2019, Rockpoint and Campus met to discuss the new offering. On the same date, Torxen, by way of letter to Campus, pointed out the significant increase in the firm and interruptible tolls. In June 2019, Campus advised Pine Cliff, Rockpoint and Torxen that the TSAs were terminated effective 30 June 2019.

Views of the Commission

Just and Reasonable Tolls

The CER noted that the parties in this case tendered lengthy submissions regarding market-based and cost of service methodologies. The CER stated that it will always consider the specific circumstances of and the evidence provided by the parties when exercising its broad discretion to assess whether tolls are just and reasonable. In this case, the CER was of the view that both methodologies, if applied strictly, would be potentially problematic for the Pipeline and its shippers. The CER was persuaded that Campus requires a degree of flexibility to achieve efficient outcomes for the Pipeline, but also found that a firm service toll range that is more cost reflective than the range applied for by Campus is just and reasonable. Accordingly, the CER determined that Campus may exercise its discretion and establish term-differentiated firm tolls, provided that such firm service tolls do not exceed $0.22/GJ.

With respect to the NEB's approval of the Pipeline and reasons in GH-2-2000, the CER was of the view that the original toll methodology is not determinative as to whether current tolls are just and reasonable. The Complainants are not barred from arguing that cost of service information is relevant to the current Application and challenging whether the applied-for tolls are just and reasonable. The CER further noted that there is no bar to Campus arguing that tolls should be approved using a methodology similar to the submissions of the applicant in GH-2-2000 and the CER noted that regulatory predictability is a relevant consideration. In this decision, the CER noted it does not intend to re-allocate the balance of risks and rewards on the Pipeline. Campus has operated and continues to operate bearing utilization risk and the ability to structure tolls to be market-responsive and incent utilization. The CER noted that Campus aspires to grow throughput and attract volumes to the Pipeline, and the CER was of the view that Campus should retain the flexibility to work together with its shippers to find market solutions in the future.

Nonetheless, the CER was of the view that Campus did not establish the appropriateness of a purely market-based toll. By its nature, a market-based toll involves limited inquiry into the cost drivers of the pipeline and the returns earned by the pipeline. To establish such a toll is just and reasonable, the NEB has previously expected a company to demonstrate a high degree of market acceptance of the toll, an absence of market power that could result in abuse, and fair and transparent engagement between the pipeline and its shippers and interested parties. The CER expects that, in general, an appropriate sharing of risks and benefits has likely been allocated between the pipeline and its shippers if these indicators are well established. While these indicators are relevant in the current case the overall test remains that tolls must be just and reasonable.

After weighing the evidence of this proceeding and considering the current circumstances of the Pipeline, the CER decided to approve a cost-informed toll range within the existing toll framework for the Pipeline. This framework includes being regulated as a Group 2 company, offering term-differentiated firm tolls, and managing its risks outside of a cost of service methodology. In setting a cost-informed toll range, the CER used the cost information provided by both parties with a view to determining a toll range between the market-based tolls applied for by Campus and the previous AltaGas tolls urged by the Complainants. Under a tolling method that is not purely cost of service, the consideration of costs must be weighed against the balance of risks shared between the Pipeline and its shippers. In considering the current complaint, costs can assist in determining the reasonableness of the tolls when framed by the risk balance between parties.

The CER noted that complete cost of service information was not provided and a true cost of service toll for service on the Pipeline could not be exactly determined. However, using the agreed upon rate base, Campus' cost allocation methodology, the Complainants' depreciation rate and a moderate cost of capital, the CER estimated that a cost-based toll would likely fall within the range of the previous five-year firm toll of $0.165/GJ and the proposed five-year firm toll of $0.22/GJ. The CER found that tolls within this range should adequately protect shippers against Campus' potential ability to exert market power, while still providing Campus sufficient opportunity to be reasonably compensated. The CER found that a toll in the above range is just and reasonable and, on that basis, directed Campus to re-issue term-differentiated tolls not exceeding $0.22/GJ.

Interruptible Transportation Tolls

Campus proposed to increase its IT tolls on the Pipeline from $0.1815/GJ to $0.32/GJ for IT service. Campus also requested that the CER grant Campus the discretion to post a revised IT toll from time to time based on Campus' assessment of prevailing market conditions, in an amount equal to or less than the proposed IT toll.

When considering the relative value of services a pipeline offers, the CER noted that it considers many factors such as the priority, availability and reliability of the service; the level of commitment required from the shipper; and flexibility or other desirable attributes provided by the service. The CER found that granting Campus the discretion to set tolls for IT service at $0.32/GJ or lower will provide Campus with the ability to respond to market circumstances and manage risks on the Pipeline.

Interim IT Tolls

On 27 June 2019, the NEB ordered that the Pipeline's tolls be made interim effective 1 July 2019. Campus requested an Order from the CER directing shippers who have received new firm or interruptible service on the Pipeline since 1 July 2019 to pay to Campus the difference between the interim tolls and the tolls payable under the Revised Tolls and Tariff for the interim period. Campus also requested the discretion to post a revised IT toll from time to time based on Campus's assessment of prevailing market conditions, in an amount equal to or less than the IT toll proposed in the Revised Toll and Tariff. Campus also submitted that it removed the Annual Increase of Tolls and Charges notice because it desires the flexibility to adjust its IT tolls on a monthly basis in response to prevailing market conditions.

The CER noted that it was not aware of a discretionary toll being approved retroactively, and the parties in the proceeding did not provide sufficient evidence for the Commission to determine the discretionary toll levels over the interim period. The interim toll for IT service was $0.1815/GJ. Without knowing the market-responsive IT tolls that would have been set in the interim period, the CER found it impossible to calculate refunds or recoveries. Factoring in interim toll evidence and in considering that Campus had the overall onus to support its position on this issue, the CER made the interim IT tolls final for the period of 1 July 2019 to 30 April 2021. Campus did not meet its onus with respect to its request for an interim toll refund. For clarity, the CER ordered Campus not to refund or recover any part of the IT tolls charged under the interim order.

Interruptible Preferred Service

The CER accepted Campus' assertion that ITp service features provide firm service shippers with greater operational flexibility and may incent shippers to subscribe for firm service and approved ITp service on the Pipeline at an amount corresponding with the shipper's FT service toll plus $0.02.

NOVA Gas Transmission Ltd. Application for the West Path Delivery 2022, CER Letter Decision F36C3 Filing C12756
Natural Gas

On 1 June 2020, NOVA Gas Transmission Ltd. ("NGTL") filed its application for permission to construct and operate the West Path Delivery 2022 (the "Project"), (the "Application"). NGTL requested an exemption from the provisions of paragraph 180(1)(a) and Section 198 of the *Canadian Energy Regulator Act* ("*CER Act")* for the Project, as well as exemption from the requirements of paragraph 180(1)(b) and subsection 213(1) of the *CER Act* to obtain leave to open ("LTO") prior to installing tie-in assemblies on the pipeline components of the Project and to put the meter station modifications component of the Project into service.

The CER considered submissions from interested parties, including Environment and Climate Change Canada, O'Chiese First Nation ("OCFN"), and Stoney Nakoda Nation ("SNN"). In this decision, the CER found it to be in the public interest to grant the requested relief and to approve the application.

Project Overview and Process

NGTL requested permission to construct and operate two non-contiguous pipeline loop sections of 1219 mm outside diameter pipe Nominal Pipe Size ("NPS") 48 natural gas pipeline that will loop NGTL's existing Edson Mainline Loop No. 4 and NGTL's existing Western Alberta System ("WAS") Mainline Loop No. 2; and expansion of NGTL's existing Alberta British Columbia Border Meter Station (ABC Border MS) (No. 1 and No. 2). The two pipeline sections are the 18 kilometers ("km") Edson Mainline Loop No. 4 - Raven River Section ("Raven River Section") near Sundre, Alberta and the 5 km WAS Mainline Loop No. 2 Alberta British Columbia Section ("ABC Section") near Coleman, Alberta.

The purpose of the Project is to increase the NGTL system capacity to meet contractual obligations for transportation and delivery of gas on the NGTL system to the ABC Border Meter Station.

The Assessment of the Application

Land Matters

NGTL stated that the Project is located on Crown and freehold lands and consists of two pipe sections, the Raven River Section and the ABC Section. The Project also includes the ABC Border MS Expansion. The Raven River Section consists of approximately 18 km of NPS 48 pipe and crosses mainly Crown land. For approximately 79% of the route, the pipeline will parallel existing disturbances. In this section, the acquisition of around 49.3 hectares ("ha") of new land would be required. The ABC Section consists of 5 km of NPS 48 outside pipe and would cross 62 per cent freehold land. For approximately 90 per cent of the route, the pipeline would parallel existing disturbances.

The construction ROW will be a minimum of 32 m wide with additional temporary work space ("TWS") of variable widths at staging areas, side bends, crossings, and grading. NGTL indicated it would utilize existing NGTL land rights to minimize the permanent ROW.

The CER recognized NGTL's efforts to minimize potential environmental impacts of the Project and to minimize the need for new land where practicable. It found the anticipated requirements for both temporary and permanent land rights to be appropriate for safe and efficient construction and operation. The CER found that necessary land rights acquisitions by NGTL will meet the requirements of Section 321 to 323 of the *CER Act.* NGTL's land acquisition process for TWS and third-party consent and the process for the acquisition of both permanent and temporary lands is expected to be completed in late 2021. The CER found that land matters had been addressed appropriately.

NGTL's Engagement with Indigenous Peoples

NGTL initially identified potentially affected Indigenous peoples based on the location of the project within known or associated territories, regional boundaries and areas of interest. The initial identification was compiled through research, past projects and experience. NGTL had later also contacted the CER to request the preliminary list of potentially impacted Indigenous peoples for the Project.

Indigenous peoples expressed general Project-related concerns to NGTL, including:

- challenges with the deadline to provide feedback and responses;
- timing of field studies;
- lack of capacity funding to participate in a review; and
- COVID-19 pandemic challenges.

The CER indicated that the engagement efforts need to be considered in the context of the expectations set out in the Filing Manual. NGTL is expected to undertake engagement activities in accordance with the principles of meaningful engagement. The CER found that NGTL appropriately identified potentially impacted Indigenous peoples and that all potentially impacted Indigenous peoples had been notified and given the opportunity to comment on the Project. The CER noted that NGTL offered capacity funding to potentially affected Indigenous peoples and that NGTL had committed to continue engagement activities during all Project phases. The CER was generally satisfied that NGTL addressed the guidance and requirements outlined in the Filing Manual.

Effects on the Rights of the Indigenous Peoples of Canada

Project components in the Raven River Section are located within the boundaries of Treaty 6, within the areas of interest of 18 potentially affected Indigenous peoples. The ABC Section is located in the boundaries of Treaty 7 and is also within the areas of interest of 19 potentially affected Indigenous peoples. Additionally, NGTL noted that the ABC Border MS Expansion is located within the historic boundaries of Treaty 7 and is also within the areas of interest of 19 potentially affected Indigenous peoples, however, this portion of land is freehold land owned by NGTL.

Potential Effects

NGTL submitted that it had taken various steps to engage with potentially affected Indigenous peoples to gather traditional knowledge and information regarding Indigenous and Treaty rights and traditional land and resources use ("TLRU") activities and how these are exercised or practiced in the Project area.

NGTL confirmed that the Project has the potential to interact with the rights of the Indigenous peoples of Canada recognized and affirmed by Section 35 of the *Constitution Act, 1982*. NGTL stated that interactions might occur during the construction of the Raven River Section and ABC Section as a result of various construction or construction-related activities. The potential effects of the Project could impact how and where Indigenous groups could exercise their TLRU and how they may be able to access the resources. NGTL provided mitigation measures for the Raven River and ABC Sections that would limit the impact of the Project by marking sensitive areas for protection and educating all workers about cultural awareness and sensitivity. NGTL would further supply the Indigenous peoples with extensive information about the Project and its construction. NGTL would further limit authorized access to a minimum and discourage unauthorized access. NGTL would further undertake ongoing engagement with potentially affected Indigenous peoples.

NGTL confirmed that while residual effects of the Raven River and ABC Sections on the exercise or practice of Indigenous and Treaty rights are likely to occur, the overall degree to which the Project component may result in residual adverse effects on the exercise or practice of Indigenous and Treaty rights in both sections' Local Assessment Area ("LAA") is reduced taking into account NGTL's commitment to mitigation and enhancement measures, along with ongoing engagement through the construction and operating life for both the Raven River and ABC Sections.

The CER noted that it has the technical expertise and mandate to consider and address project impacts, including those affecting the rights and interests of Indigenous peoples. In its evaluation of the consultation and accommodation, the CER considered all project-specific details and submissions.

Based, in part on factors such as NGTL's consultation with Indigenous peoples for the Project, notice and sufficiency of information about the Project being provided to Indigenous peoples, the evaluation process for the Project, and participation opportunities within that process, the CER found there to have been adequate consultation and accommodation. The CER acknowledged NGTL's efforts and measures to reduce impacts on the exercise of Indigenous and Treaty rights by designing its route to parallel existing disturbances wherever feasible. The CER also found that opportunities provided by NGTL, including providing various detailed information such as Project maps, as well as offering engagement capacity funding agreements, facilitating site visits and traditional knowledge studies with interested Indigenous peoples, and responding to issues raised, provided potentially affected Indigenous peoples with reasonable opportunity to identify any concerns.

As NGTL had entered into agreements with some potentially impacted Indigenous peoples to conduct community-directed Indigenous knowledge studies for the Project and that some studies were still outstanding, the CER imposed Condition 6 to ensure that the revisions necessitated by the studies are properly incorporated into the environmental protection plan ("EPP"). The CER also imposed Condition 10, requiring a commitment tracking table, and Condition 13, regarding Post-Construction Monitoring Reports, to enhance transparency and further minimize impacts.

The CER noted its understanding that NGTL's commitment to mitigation and enhancement measures would diminish the degree to which the Project components may result in residual adverse effects on the exercise or practice of Indigenous and Treaty rights. However, to further enhance transparency, the CER imposed Condition 7 regarding an Indigenous peoples employment, procurement and contracting plan. Condition 12, regarding Indigenous peoples' employment, contracting and procurement reporting, was also imposed.

Following consideration of all evidence submitted, the CER was satisfied that its decision is consistent with subsection 35(1) of the *Constitution Act, 1982.*

Effects on the Rights of O'Chiese First Nation

The CER found that NGTL's mitigation measures combined with NGTL's Cultural Resource Discovery Contingency Plan and the imposed conditions establish reasonable layers of protection for previously identified and unidentified cultural sites. While the CER reviewed all submitted information and efforts made by NGTL to engage and collaborate with OCFN, it imposed conditions 5, 8 and 10 to further help identify and avoid cultural sites.

Environmental Matters

The CER noted NGTL's commitment to updating the project-specific EPP with the additional mitigation required based on the results of surveys. In order to ensure that the additional site-specific mitigation measures identified from the 2020 field surveys, as well as the consultation with the responsible regulators, is incorporated into the EPP, the CER imposed Condition 4 for an Updated EPP.

The CER noted NGTL's commitment to conduct post-construction monitoring and emphasized the importance of a post-construction environmental monitoring program for the mitigation of potential adverse effects. To be satisfied that post-construction environmental monitoring is thorough and effective, the CER imposed Condition 13 requiring NGTL to implement a post-construction environmental monitoring program for a five-year period and submit Post-Construction Environmental Monitoring Reports to the CER bi-annually. It found that with the implementation of NGTL's environmental protection procedures and mitigation and the conditions imposed by the CER, the Project is not likely to cause significant adverse environmental effects.