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.

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ALBERTA COURT OF APPEAL

***FortisAlberta Inc. (Applicant) and Alberta Utilities Commission, EQUS REA Ltd., Rocky Rural Electrification Association Limited and Alberta Federation of Rural Electrification Associations Ltd. (Respondents),* 2020 ABCA 271**
Permission to Appeal - Cost Claim

Introduction

FortisAlberta Inc ("Fortis"), a public utility, applied for permission to appeal from a decision of the AUC dated April 17, 2020. The ruling related to what were said by Fortis to be costs claims that were properly to be included in a distribution tariff presented for approval to the AUC by Fortis.

In that decision, the AUC found that it did not have the statutory authority to approve, under the Phase II Distribution Tariff Application ("DTA") process followed by Fortis, a form of "recovery" by Fortis of what was described by Fortis as "integrated distribution system costs". The AUC mentioned that those costs were also described by Fortis with the more elaborate name "REA (Rural Electrification Association) Wire Owner — Integrated System Charges." The costs in question (the "Disputed Costs") were said by Fortis to arise for Fortis in their overlapping and linked operations with each rural electrification association ("REA").

The respondents argued that the Legislature established and has maintained as the structure for intervention and reconciliation respecting overlapping costs as between a public utility like Fortis and each REA what are called "integrated operations agreements" ("IOAs") under the *Electric Utilities Act* and the *Roles, Relationships and Responsibilities Regulation* ("*3R Regulation*") under that Act. The respondents further submitted, and the AUC agreed, that the Disputed Costs are covered by the IOAs and that is the exclusive arrangement within which to address them. The IOAs are subject to an arbitration process — a process which, the Court noted, appears to be by consensus even more flexible than what is set out in the *3R Regulation*.

Fortis requested permission to appeal on the following question:

> Did the AUC err in ruling that it does not have the authority to approve the recovery of the Distribution Costs that [Fortis] proposed to allocate to, and to recover from, REAs?

The Court stated that Fortis argued that it needed guidance from the Court about the meaning of the relevant legislation, asking the Court to provide "clarity" so that all participants in the DTA would better understand the criteria for determining what sort of costs are eligible under the DTA process. Put another way, the inclusion of the Disputed Costs in the DTA process would, in Fortis' submission, mean that the expert and impartial AUC would be able to ensure that a consistent and balanced approach to address tariff items would exist across the board. Fortis further stated that the AUC is well equipped and informed to determine what are just and reasonable rates. The AUC would, under this approach, not merely determine the eligibility of costs and expenses for Fortis as a public utility vis-à-vis its customer base, but could also address the universe of Fortis costs including those related to the relationship between Fortis with each REA.

Fortis filed its DTA under s 102(2)(a) of the *Electric Utilities Act* on January 17, 2020.

Section 102(1) and (2) of the Electric Utilities Act reads as follows:

> Distribution tariff
>
> 102(1) Each owner of an electric distribution system must prepare a distribution tariff for the purpose of recovering the prudent costs of providing electric distribution service by means of the owner's electric distribution system.
>
> (2) The owner of the electric distribution system must apply for approval of its distribution tariff
>
> > (a) to the Commission,
> >
> > (b) to the council of a municipality, if the owner is a municipality or a subsidiary of a municipality

> (i) that does not have an affiliated retailer that provides retail electricity services outside the service area of the municipality, and
>
> (ii) that does not provide electric distribution service outside the service area of the municipality either on its own behalf or on behalf of another owner,
>
> or
>
> ***(c) to the board of directors of the association, if the owner is a rural electrification association.*** [Emphasis added.]

The Court noted that in the words of s 102, the DTA was to have largely focused on what Fortis should be allowed to recover for "prudent costs" for providing electricity services provided by it by means of its "electric distribution system". Fortis and the REAs, strongly differed on whether s 102(2)(a) is intended to allow the AUC to authorize Fortis to "recover" from anyone but its "customers".

The Court wrote that the REAs argued that the Legislature has maintained as the structure for intervention and reconciliation respecting overlapping costs via the arrangements for creation and review of the IOA under the *Electric Utilities Act* and the *3R Regulation*. They argued that the proposed extension of the authority for the AUC to being one that could summarily override what the IOAs say or do not say on this topic, is not only unnecessary, it would undermine the purpose and effectiveness of the IOAs and the *3R Regulation* and render the role of arbitrators nugatory.

The Court noted that another key legislative feature is section 122(1) of the *Electric Utilities Act* which guides the AUC in assessing a tariff including a distribution tariff and which provides in part as follows:

> *Costs and expenses recovered under a tariff*
>
> 122(1) When considering a tariff application, the Commission must have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover
>
> …
>
> (b) other prudent costs and expenses associated with isolated generating units, transmission, exchange or distribution of electricity or associated with the Independent System Operator if, in the Commission's opinion, they are applicable to the electric utility,
>
> …
>
> (h) any other prudent costs and expenses that the Commission considers appropriate, including a fair allocation of the owner's costs and expenses that relate to any or all of the owner's electric utilities.

<u>Decision of the AUC</u>

In its reasons, the AUC noted Fortis' submissions regarding broad jurisdiction given to the AUC under s 85(1) of the *Public Utilities Act*, RSA 2000, c P-45, and ss 8 and 11 of the *Alberta Utilities Commission Act*. It also noted Fortis' argument grounded on s 122 of the *Electric Utilities Act* as to what would constitute legitimate expenses including under the basket clause of s 122(1)(h) of that Act.

After describing the developments respecting the EQUS-Fortis IOA, and considering the overall scheme, the AUC concluded that the *3R Regulation* and the IOAs were the proper locations for reconciliations about shared costs between each REA and Fortis:

> 39 While the word "cost(s)" is not in the *Roles, Relationships and Responsibilities Regulation*, 2003, the Commission considers that "an agreement between owners respecting the integrated operation of their electric distribution systems in a single geographic region," on a plain and ordinary reading, read in its entire context, and consistent with the scheme of the relevant acts and regulations, includes any costs or charges associated with that integrated operation. This is supported by a review of the legislative scheme, the absence of the phrase "integrated operation agreement" in the Electric Utilities Act, as well as the provisions in the IOAs themselves, in which the parties agreed (or the arbitrator approved) provisions addressing costs.

The AUC went on to quote provisions of the EQUS-Fortis IOA and noted again the pendency of arbitration as to that IOA on the very subject of cost allocation. The AUC also found that EQUS REA Ltd. was not a "customer" of Fortis as defined in s 1(1)(h) of the *Electric Utilities Act* which reads: "'customer' means a person purchasing electricity for the person's own use". Explaining this conclusion, the AUC noted the link of that language to provisions dealing with an "electric distribution system" and "electric distribution service". The latter "service" under the definition in the *Electric Utilities Act* meant the service required to transport electricity to "customers" or from a generation facility to the interconnected system by means of an "electric distribution system".

The Court noted that the AUC effectively found that the Legislature had disposed of the idea that a distribution tariff for Fortis could include costs it claimed to incur as a result of its contractual relationships with the REAs who were not customers. The AUC also found that the language of s 122 of the *Electric Utilities Act* did not cover the new form of cost claim pressed by Fortis. As a result, the AUC found that it did "not have the authority to approve the applied-for allocated distribution costs as part of Fortis's distribution tariff".

Discussion

The Court noted that Fortis submissions as to the *prima facie* merits included that, as background to its complaint to the AUC, that it was being forced to contribute more than its share to the costs of operations provided in service areas covered by each REA and linked to Fortis. Fortis alleged that each REA utilized the Fortis electricity distribution system more than Fortis used the respective REA system. Fortis said that this inequity was reflected in the inability of Fortis to charge the REAs for their unrequited share of the Disputed Costs.

The Court wrote that Fortis contended that the AUC had jurisdiction under the distribution tariff process to make an authoritative statement somehow leading to making each REA contribute to Fortis for the Disputed Costs arising from the REA being interconnected with the Fortis system. On this premise, the shared costs suffered by each REA would then presumably be passed through to customers of each REA. Fortis further suggested that this would mean that those customers would then ultimately be paying a more accurate share of the costs of their electrification services and would be more equitably sharing common costs with Fortis customers. To avoid 'tariff shock' for REA customers, Fortis did not propose to phase in 100% of the thus newly recognized shared costs.

The Court noted the REAs' argument that Fortis' submission in its DTA imagined a novel AUC authority which would upset the longstanding status quo governed by the IOA arrangements. The REAs argued that Fortis was proposing the creation, without the blessing of clear legislative approval, of an overarching AUC power to impose terms such as would otherwise be negotiated within IOAs or arbitrated. The REAs further argued that Fortis had to persuade AUC of the validity of this theory and Fortis failed to do so. The Court noted that this position for the respondents was compelling.

The Court wrote that the REAs did not dispute that Fortis can try to persuade AUC to approve a tariff which Fortis considers reasonable for Fortis to operate viably and profitably, viz "prudent costs". But they argued that the DTA process ultimately provides Fortis the opportunity to validate its *own* tariff to recover prudent costs from its *own customers.* The REAs noted that they are not customers of Fortis. Put another way, the REAs argued that the Fortis approach here is a semantical sleight of hand asking the AUC to re-balance expenses as between electricity suppliers without deferring to the IOA contracts and the *3R Regulation*.

In the Court's view, it was not arguable that the AUC was incorrect in attaching significance to the fact that the REAs were not customers of Fortis or that the AUC misconceived the indicia from the legislation about where to find the harmony in and between the statutes and the *3R Regulation*.

The application for permission to appeal was dismissed.

ALBERTA ENERGY REGULATOR

***Invitation for Feedback on Draft Directive on Well Integrity Management*, AER Bulletin 2020-16**

Bulletin - Invitation for Feedback - Well Integrity Management

On July 16, 2020, the AER announced it is seeking feedback on a new draft directive, *Directive XXX: Well Integrity Management*. The new draft directive contains testing, reporting, and repair requirements for isolation packers, surface casing vent flows, gas migration, and casing failures. It will rescind and replace *Interim Directive ID 2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Venting Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements* and incorporates guidance previously given in AER Bulletin 2009-07 and AER Bulletin 2011-35.

The new draft directive also includes the following changes to existing requirements:

- isolation packers in Class II injection and disposal wells would be tested triennially instead of annually;
- nonserious surface casing vent flows would be tested in years one, two, and six instead of every year for five years; and
- routine repairs would only need AER approval after three failed attempts instead of one.

The AER indicated that feedback would be accepted through August 17, 2020.

***New Edition of Directive 060*, AER Bulletin 2020-15**

Bulletin - New Edition of Directive 060

On July 7, 2020 the AER released a new edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. Section 2.6 was updated to permit the use of incinerators and enclosed combustors between 100 m and 500 m of a residence for facilities with first gas disposition after January 1, 2020. For such facilities, where unconserved gas volumes greater than 900 m^3/day are combusted, the gas must be disposed of in an incinerator or enclosed combustor. The AER clarified that the 500 m residence spacing requirement for flaring or venting has not changed.

ALBERTA UTILITIES COMMISSION

***Review of AUC Rule 017: Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission*, AUC Bulletin 2020-24**

Bulletin - Review of AUC Rule 017

The AUC stated that the Government of Alberta introduced the *Red Tape Reduction Act* to reduce regulatory burden and improve regulatory efficiency. The AUC explained that agencies, including the AUC, form part of this commitment. The AUC is therefore reviewing not only its processes and procedures, but also its rules in order to reduce the regulatory requirements contained within the rules. This includes a review of AUC *Rule 017.*

The AUC is proposing amendments to AUC *Rule 017* that will:

- remove references to the capacity market;
- introduce a new streamlined consultation and application process for making administrative changes to existing Independent System Operator rules; and
- remove mandatory filing requirements in the rule.

The AUC noted that its review of *Rule 017* would consist of a stakeholder consultation involving a written process. The deadline for submitting comments was July 14, 2020.

***Reducing Regulatory Burden With Materiality Thresholds for Review of Cost of Service Rate Applications*, AUC Bulletin 2020-25**

Bulletin - Rates - Reducing Regulatory Burden

One of the key themes articulated in the AUC's strategic plan for 2019-2022 was increased efficiency and reduced regulatory burden. The AUC indicated it understands the importance of cost-effective, timely, and proportionate regulation and has undertaken a new initiative to improve the efficiency of its review of cost of service rate applications. The AUC explained that materiality thresholds create a more effective and efficient regulatory process by focusing examination on material issues and by avoiding the time, effort, and resulting costs to investigate marginal cost differences.

The AUC announced that effective immediately, it is implementing materiality thresholds for testing the revenue requirement for operations and maintenance ("O&M") costs in cost of service applications. Materiality thresholds will be used to test variances between approved, actual, and forecast O&M costs. Materiality will be applied to O&M accounts at the uniform system of account and prime account level and the threshold will vary depending on the total forecast revenue requirement of the utility as follows:

Revenue requirement	Percentage variance	$ variance	Threshold rule
Less than $100 million	3	75,000	Greater of 3% and $ variance
$100 million to $250 million	3	100,000	
$250 million to $500 million	3	250,000	
More than $500 million	3	400,000	

The AUC stated that variances below these thresholds would not be expected to be explained by the applicant nor questioned by the AUC or other parties. However, a review of costs or issues below the materiality threshold will be permitted if the cost item or issue is precedent-setting or invokes regulatory accounting principles, adherence to AUC rules, or previous directions. The AUC noted that any request for an exception to examine a cost below these thresholds must be supported by a compelling explanation of the rationale, precedent, or principle at stake. Absent an AUC order allowing for exceptions, information requests or other materials purporting to examine costs below these materiality thresholds would be excluded from the record of this proceeding and any related costs claimed will be disallowed.

***AUC Extends Suspension of Specified Penalties Program for Self-Reported Contraventions to September 30, 2020*, AUC Bulletin 2020-26**

Bulletin - Extension to Specified Penalties Program

On March 27, 2020, the AUC issued *Bulletin 2020-10: Suspension of Specified Penalties Program for Self-Reported Contraventions*, which suspended the issuance of notices of specified penalties for self-reported contraventions until June 18, 2020. The AUC announced it has extended the operation of Bulletin 2020-10 until September 30, 2020. The AUC explained that this extension would promote the self-disclosure of contraventions while still allowing Alberta's electric and natural gas utilities, service providers, and retailers to continue their focus on helping their customers during the ongoing COVID-19 crisis.

In addition to the measures set out in Bulletin 2020-10, the AUC indicated it would continue to exercise its regulatory discretion around the issuance of notices of specified penalties under *Rule 032: Specified Penalties for Contravention of AUC Rules*. Until September 30, 2020, the AUC stated it would limit its consideration of specified penalties to contraventions that are not self-reported, or that resulted in disconnections of a customer's site in error for a period in excess of 24 hours regardless of whether or not the contravention was self-reported.

***Suspension of Commissioning and Notarizing Requirements*, AUC Bulletin 2020-27**

Bulletin - Commissioning and Notarizing Requirements

On May 6, 2020, the AUC issued *Bulletin 2020-16: Requirements for Costs Claim Applications and Confidentiality Undertakings*, which suspended the requirement to have a confidentiality undertaking witnessed. The suspension recognized that current restrictions in place in response to the COVID-19 pandemic could interfere with a participant's ability to appear before another person for the purpose of having a document witnessed or sworn.

In recognition that there are other forms and documents filed with the AUC that contemplate the party executing it before a commissioner for oaths or notary public, the AUC announced it is suspending the requirement to have these forms and documents commissioned or notarized in light of the current and ongoing circumstances. The forms and documents must still be completed and filed when required on the applicable proceeding or as otherwise provided to the AUC.

***Alberta Utilities Commission Discussion Paper on Power Plant Self-Supply and Export*, AUC Bulletin 2020-28**

Bulletin - AUC Discussion Paper - Power Plant Self-Supply and Export

In the fall of 2019, the AUC conducted stakeholder engagement on the issue of power plant self-supply and export.

On June 5, 2020, the AUC provided the Department of Energy with a discussion paper which detailed the background and evolution of power plant self-supply and export in Alberta and summarized the views of market participants on how best to address that issue in the future. In the discussion paper, the AUC also identified 21 legacy facilities that appear to be engaged in self-supply and export without an industrial system designation ("ISD"). Approximately two-thirds of the legacy facilities (representing 90 percent of capacity) are cogeneration units that may be eligible for an ISD. The AUC indicated it is prepared to work directly with these operators to assess proactive ISD qualification.

The AUC has also explained that the approval holders for these legacy facilities have been operating their plants based upon a reasonable reliance on the approvals granted to them. Thus, the AUC confirmed that it does not consider that these approval holders have engaged in any form of intentional misconduct or non-compliance. Both the AUC and the Market Surveillance Administrator have stated that they are not investigating legacy facilities and do not intend to investigate legacy facilities while the Department of Energy's consideration on the policy pertaining to power plant self-supply and export is ongoing.

The AUC noted that it would consult with the Department of Energy on next steps in the stakeholder engagement process and stakeholders would be advised of those steps in due course.

Alberta Electric System Operator - Application for Review and Variance of Decision 790-D06-2017, **AUC Decision 25150-D02-2020**

Review and Variance - AESO Rules - Line Losses

Decision Summary

In Decision 25150-D01-2020, the AUC determined that it would hear an application filed by the Alberta Electric System Operator ("AESO") to vary specific findings pertaining to the timing and approach for the collection and reimbursement of funds related to historical line loss charges and credits ("Settlement Findings") in Decision 790-D06-2017[2] ("D06 Decision").

In this decision, the AUC determined whether to vary the Settlement Findings in the D06 Decision, and if so, what settlement schedule should be implemented. The AUC found that the Settlement Findings in the D06 Decision should be varied from a single settlement process to a settlement process that is completed in three settlement periods.

Background

On December 3, 2019, the AESO filed an application seeking a review and variance ("R&V") of the AUC's order in the D06 Decision, which implemented a single settlement of Module C loss factor charges and credits. The AESO requested that the AUC vary its Settlement Findings from a single settlement approach to a pay-as-you-go approach. The AUC agreed to hear the R&V application outside of the 60-day deadline.

In this decision, the AUC panel that authored the D06 Decision is referred to as the "Hearing Panel."

Consideration of Settlement Options

Single Settlement

The Hearing Panel's findings in the D06 Decision directing the implementation of a single settlement approach are found in paragraphs 143 to 157 of the decision. The Hearing Panel summarized the single settlement approach as follows:

> A single, net settlement approach with one net charge collected or reimbursed to market participants only after all loss factors have been calculated for the historical period (single settlement).

The Hearing Panel directed a single settlement approach principally because it would "provide parties with the opportunity to review the results for each year, before new statements of account are issued" and "be most efficient, from an administrative perspective, to wait until all years are calculated before issuing a final statement of account for the full historical period." The Hearing Panel recognized that a single settlement approach would delay refunds longer as compared to a pay-as-you-go approach that was presented at that time and sought to mitigate the consequence of that additional delay through interest charges.

Pay-As-You-Go Settlement

In the D06 Decision, the Hearing Panel summarized the pay-as-you-go settlement approach as follows:

> A pay-as-you-go settlement approach, with a charge or reimbursement made to market participants once the loss factors had been calculated for one or more years and repeated sequentially until all historical years have been settled (pay-as-you-go settlement).

In that decision, the Hearing Panel stated that it was uncertain whether a pay-as-you-go approach would result in significant variability between charges and credits as each year of the historical period was calculated and consequently, it was not prepared to direct pay-as-you-go settlement. The Hearing Panel also stated that a pay-as-you-go approach could result in the imposition of an additional administrative burden if the AESO was required to deal with payment defaults.

Alternative Settlement Options

The AUC invited comments on two alternative options that would divide financial settlement into either two or three settlement periods.

(a) Completing the settlement in three periods: three years, four years, and a final four years. (Option 1)

(b) Completing the settlement in two periods: three years and eight years. (Option 2)

AUC Findings

On December 18, 2017, the Hearing Panel issued the D06 Decision based on representations from the AESO at that time that it would take 13 months to implement loss factor charges for the historical period. The Hearing Panel directed the implementation of a single settlement process recognizing that it would result in the delay of refunds. Approximately 24 months later, the AUC received this application from the AESO indicating that "… completion of single settlement of charges and credits will require approximately 19 to 30 months instead of the 9 to13 months duration that the AESO originally estimated."

It was noted that in the first stage of the review (Decision 25150-D01-2020), the AUC acknowledged the complexity of calculating historical loss factor charges and stated that it is in the interest of all parties that related charges be settled as soon as reasonably possible. The AUC accepted the submissions of parties that the speed of financial settlement should be the primary consideration in determining whether the D06 Decision should be varied. Notwithstanding, the AUC noted that it is also important that the AESO has sufficient time to accurately prepare the settlement calculations and that there is a timely process to resolve any disputes that may arise with the settlement calculations as they are being completed. The AUC found that the imposition of Option 1 will achieve the appropriate balance between the need to proceed as expeditiously as possible while also allowing review and conciliation of disputes as the calculations for each settlement period are completed.

The AESO submitted that if the AUC were to approve a settlement approach by early July 2020, it expected that settlement of years 2016, 2015 and 2014 would occur by September 2020. Given the time that had already elapsed and based on the AESO's representation that calculations for the initial three years were nearly completed, the AUC found that the settlement of these first three years should occur as soon as possible.

The AUC varied the direction to the AESO in the D06 Decision, which required the implementation of a single settlement approach for the historical period with simultaneous collection and reimbursement by directing the AESO to implement three settlement periods including one of three years, and two four-year periods for the historical period with simultaneous collection and reimbursement pursuant to the ISO tariff.

***AltaGas Utilities Inc. Application to Rescind a Deemed Affiliate Designation Between AltaGas Utilities Inc. and AltaGas Ltd., Including AltaGas Ltd.'s Subsidiaries*, AUC Decision 25565-D01-2020**
Rescinding of Affiliate Designation

In this decision, the AUC considered whether to approve an application brought by AltaGas Utilities Inc. to rescind a deemed affiliate designation between AltaGas Utilities Inc. and AltaGas Ltd. and its subsidiaries. This would involve minor changes to AltaGas Utilities Inc.'s Inter-Affiliate Code of Conduct and associated Inter-Affiliate Code of Conduct Compliance Plan. The AUC found that AltaGas Utilities Inc. had demonstrated that AltaGas Ltd. and its subsidiaries no longer had any ownership interest or significant influence over AltaGas Utilities Inc. For this reason, the AUC approved AltaGas Utilities Inc.'s application as filed.

Application Background

On January 5, 2005, when AltaGas Utilities Inc's. Inter-Affiliate Code of Conduct was approved by the Alberta Energy and Utilities Board, AltaGas Ltd., and AltaGas Utilities Inc. were subsidiaries under a common parent, AltaGas Income Trust ("AIT"). Between 2005 and 2020, AltaGas Ltd. and AltaGas Utilities Inc. were parties to multiple corporate restructuring transactions, including the latest divestiture of AltaGas Utilities Inc. and its parent company, AltaGas Canada Inc. (“ACI”), to PSPIB Cycle Investments Inc. Following PSPIB Cycle Investments Inc.’s acquisition of ACI, neither AltaGas Ltd. nor its subsidiaries had any ownership interest in AltaGas Utilities Inc. or its parent companies, and all transactions between AltaGas Utilities Inc. and AltaGas Ltd. were completed at arm’s length. AltaGas Utilities Inc. stated that the deemed affiliate designation between itself and AltaGas Ltd. and its subsidiaries was no longer necessary and requested that it be rescinded.

<u>AUC Findings</u>

The AUC determined that AltaGas Utilities Inc. and AltaGas Ltd. and its subsidiaries did not meet the definition of “affiliates” as defined in section 2 of the *Business Corporations Act*. The AUC also agreed with AltaGas Utilities Inc.’s assertion that AltaGas Ltd. and AltaGas Utilities Inc. no longer met the definition of an affiliate as described in section 2.1b)i) to iv) of AltaGas Utilities Inc.’s Inter-Affiliate Code of Conduct.

Further, the AUC found that, since AltaGas Ltd. reassigned its administrative agreement with AltaGas Utilities Inc.to ACI during a 2018 restructuring transaction, AltaGas Ltd. was no longer acting as an agent of AltaGas Utilities Inc. Therefore, the AUC confirmed that section 2.1(b)(v) of AltaGas Utilities Inc.’s Inter-Affiliate Code of Conduct would not apply.

Based on the above, the AUC agreed with AltaGas Utilities Inc. that the deemed affiliate designation between AltaGas Utilities Inc. and AltaGas Ltd. and its subsidiaries was no longer applicable.

***AltaGas Utilities Inc. Review and Variance of Decision 22570-D01-2018 Stage 2*, AUC Decision 25031-D01-2020**

Review and Variance, Rates

In this decision, the AUC considered a Stage 2 review of the deemed equity ratio for AltaGas Utilities Inc. (“AltaGas”) of 39 per cent for the years 2018 to 2020 (inclusive) approved in Decision 22570-D01-2018, and whether the 39 per cent approved deemed equity ratio should be varied. The AUC confirmed the findings in Decision 22570-D01-2018. The approved deemed equity ratio for AltaGas for 2018 to 2020, inclusive, will remain at 39 per cent.

<u>Background</u>

Decision 22570-D01-2018, the 2018 generic cost of capital decision (“2018 GCOC decision”), was issued on August 2, 2018. In that decision, the AUC approved a deemed equity ratio of 39 per cent for 2018 to 2020 for AltaGas, a reduction of 200 basis points from the 41 per cent deemed equity ratio that had been approved for 2016 to 2017 in Decision 20622-D01-2016. AltaGas applied for a review and variance (“R&V”) of the 2018 GCOC decision, pursuant to Rule 016: *Review of Commission Decisions*.

In this decision, the members of the AUC panel who authored Decision 22570-D01-2018 were referred to as the “Hearing Panel” and the members of the AUC panel considering the review application were referred to as the “Review Panel.”

Rule 016 sets out the process for considering an application for review. The review process has two stages. In the first stage, a review panel must decide whether there are grounds to review the original decision. This is sometimes referred to as the “preliminary question.” If the review panel decides that there are grounds to review the decision, it moves to the second stage of the process where the AUC holds a variance proceeding to decide whether to confirm, vary or rescind the original decision.

The first stage of AltaGas’s R&V application was considered in Proceeding 23947. The AUC’s findings were set out in Decision 23947-D01-2019[3]:

> AltaGas has demonstrated that the improved rating of AltaGas’s new parent, ACI [AltaGas Canada Inc.], represents a materially changed circumstance since the original decision was issued and that this change could lead the Commission to materially vary the findings in the original decision. Accordingly, AltaGas has

> satisfied the requirements for a review of Decision 22570-D01-2018: 2018 Generic Cost of Capital and its application for a review of the findings in paragraphs 836-843 is allowed.

AUC Findings

In the 2018 GCOC decision, the AUC found that it would not depart from its historical practice of maintaining a credit rating target in the A-range for the affected utilities.

The AUC acknowledged in the 2018 GCOC decision that AltaGas has never had access to A-grade debt, and that although it may be part of AltaGas Canada Inc's ("ACI's") stated corporate goals, there was no evidence to suggest it would be able to issue debt at A-range credit rating levels in the foreseeable future. The AUC noted that AltaGas has, in previous GCOC decisions, received the benefit of an equity ratio that reflects achieving an A-range credit rating. In the 2018 GCOC decision, the AUC determined that an adjustment to the equity ratio of AltaGas was required to recognize the incongruity between the assumption, in the approved deemed equity ratio, that AltaGas could obtain debt at A-range credit rating levels and the reality that AltaGas could not. The Review Panel noted that the question in this second stage R&V proceeding is whether, now that the parent of AltaGas has a higher B-range credit rating than it did when Decision 22570-D01-2018 was issued, AltaGas's approved deemed equity ratio should be increased by the 200 basis points that were removed in the 2018 GCOC decision.

The Review Panel noted that much of the evidence presented by AltaGas in this proceeding focused on whether the AUC should have removed the 200 basis points from AltaGas's equity thickness in Decision 22570-D01-2018; rather than whether AltaGas's equity thickness should be adjusted in light of AltaGas's improved credit rating (from BBB to BBB+) subsequent to the 2018 GCOC decision. AltaGas did not argue for a partial return of approved deemed equity ratio, but for a full return of the 200 basis points even though it had still not achieved the targeted A-range credit rating. While AltaGas stated that it "… would be open to the Commission to award a different equity thickness…," AltaGas did not offer any suggestion or support for what a partial award should be or upon what factors it would be based.

The Review Panel found that a full return of 200 basis points was not warranted because the parent of AltaGas has still not obtained the necessary A credit rating to receive the previously approved 41 per cent deemed equity ratio. It was also not persuaded by the arguments of AltaGas that the reduction to its equity ratio should not have been made by the Hearing Panel. The Review Panel noted that this ground was argued and dismissed by the AUC in the first stage R&V, and that many of AltaGas's arguments addressed issues that were rejected in the Stage 1 review and did not focus on the fundamental issue of AltaGas's parent's increased credit rating and its potential impact on AltaGas's equity ratio.

The Review Panel found that the reason for which AltaGas's equity ratio was reduced (it is not an A credit-rated utility) remained unchanged. The AUC could not therefore allow a full return of the 200 basis point equity ratio reduction. It could, however, assess whether it should consider some partial return of the 200 basis points in equity ratio. This, in turn, gave rise to the question of whether the approved deemed equity ratio should change in lockstep with the utility's credit rating.

The Review Panel agreed with a submission from the Office of the Utilities Consumer Advocate ("UCA") that had a BBB rating been specifically targeted in the Hearing Panel's determination of AltaGas's equity ratio, the value would have been much lower than the approved 39 per cent. The Review Panel noted that the Hearing Panel did not impose a deemed equity ratio for AltaGas commensurate with a BBB-range credit rating due to the magnitude of the equity ratio reduction that would be required and the resulting sizable effect on AltaGas. Given that the approved deemed equity ratio did not target the BBB-range, AltaGas's equity ratio of 39 per cent, while lower than other utilities to reflect its lower credit rating, is still within an A-range credit rating. As indicated by the UCA, the equity ratio of 39 per cent, when combined with a return on equity ("ROE") of 8.5 per cent, "well exceeds the minimum credit metrics for an A-range credit rating."

Notwithstanding the fact that at a 39 per cent equity ratio, AltaGas continues to receive the benefits of an A credit-rated utility, the Review Panel considered whether a credit rating improvement from BBB to BBB (high) for the parent of AltaGas warrants an upward adjustment to AltaGas's approved equity ratio.

The Review Panel noted that AltaGas did not argue for a partial equity ratio increase, nor did it provide any basis for arriving at a determination of a value for a partial adjustment. It was open to AltaGas, a sophisticated party represented by counsel, to adduce such evidence and make such an argument. Absent a case put forward for a partial variance, the AUC had insufficient evidence to make a determination for a partial equity ratio adjustment.

Based on the foregoing, the AUC found that the improved rating of AltaGas's new parent, ACI, is not sufficient to materially vary the findings in the 2018 GCOC decision. Accordingly, the AUC did not vary the decision and confirmed the approved deemed equity ratio of 39 per cent for AltaGas for the years 2018, 2019 and 2020.

***AltaLink Management Ltd. 2019-2021 Transmission Facility Owner General Tariff Application Compliance Filing to Decision 23848-D01-2020*, AUC Decision 25627-D01-2020**
Rates

In this decision, the AUC approved an application filed by AltaLink Management Ltd. ("AltaLink") requesting approval of its compliance filing to Decision 23848-D01-2020, AltaLink's 2019-2021 transmission facility owner ("TFO") general tariff application ("GTA"). The AUC approved the resulting revenue requirements for the years 2019-2021 as filed by AltaLink.

Background

On May 29, 2020, AltaLink filed a compliance filing application with the AUC, pursuant to the AUC's order in Decision 23848-D01-2020. AltaLink requested approval of its compliance with directions from Decision 23848-D01-2020 regarding AltaLink's 2019-2021 TFO GTA.

In Decision 24757-D01-2019, the AUC granted final approval for the transfer and sale of specific transmission assets, located on the Piikani Reserve No. 147, from AltaLink to PiikaniLink Limited Partnership ("PLP"). In the same decision, AltaLink was granted approval to allocate a monthly amount of $435,654 of its approved 2019 interim tariff to PLP, In Decision 25307-D01-2020, the AUC granted final approval for the transfer and sale of specific transmission assets, located on the Blood Reserve No. 148, from AltaLink to KainaiLink Limited Partnership ("KLP"). In the same decision, AltaLink was granted approval to allocate a monthly amount of $269,443 of its approved 2020 interim tariff to KLP.

For reasons of regulatory efficiency and cost-effectiveness, AltaLink proposed that PLP's 2019-2021 final tariffs and that KLP's 2019-2021 final tariffs be considered in AltaLink's compliance filing to Decision 23848-D01-2020. As such, AltaLink's compliance filing to Decision 23848-D01-2020 included AltaLink's responses to the decisions and directions from decisions 24757-D01-2019 and 25307-D01-2020.

AltaLink's Responses to Directions Provided in Decision 23848-D01-2020

The AUC accepted that directions 4, 7, 9, 10, 11, 12, 13, 15, 16, and 22 provided in Decision 23848-D01-2020 will remain outstanding and are to be addressed at the time of AltaLink's next GTA.

The AUC was satisfied that AltaLink complied with the requirements of directions 1, 2, 3, 5, 6, 8, 14, 18, 19, 20, and 21, in its compliance filing.

Directions 2 and 3

As per the AUC's instructions in directions 2 and 3, AltaLink provided the wildfire risk maps for the Whitecourt fire region and the White Zone, as well as a status update of the Targeted Component and Structure Replacements in High-Risk Fire Areas ("HRFAs") program (the "Targeted Program") of the Wildfire Mitigation Plan.

While the AUC was satisfied that AltaLink complied with directions 2 and 3 provided in Decision 23848-D01-2020 and acknowledged that AltaLink was not adjusting its original forecast of $24.6 million for the Targeted Program in this 2019-2021 test period, the AUC noted that the additional costs that AltaLink requires to complete work related to the Targeted Program beyond this test period (the remaining $8.3 million) were not under consideration in this proceeding. The AUC advised that if AltaLink requires additional capital expenditures to complete this work beyond the current test period, it must apply for the associated capital amounts as part of its next GTA.

The AUC raised concerns regarding lines that were part of AltaLink's capital replacement and upgrades ("CRU") program that were moved into the Targeted Program. It was not clear to the AUC whether some of the $8.3 million in costs associated with the remaining work to be completed beyond this 2019-2021 test period, resulted from this proposed shift in program. It was also not clear whether AltaLink plans to apply a corresponding reduction to its CRU costs, also agreed to in the Negotiated Settlement Agreement ("NSA"), as a result of this change. AltaLink was directed to clarify in its next GTA whether it intends to apply for additional capital expenditures to complete work related to the Targeted Program.

Direction 5

As per the AUC's instructions in Direction 5, AltaLink provided an updated table containing the length of transmission lines in km identified to be rebuilt, as well as a breakdown of forecast and actual costs incurred up to March 31, 2020, for the line rebuilds in HRFAs program of the Wildfire Mitigation Plan. The AUC was satisfied that AltaLink complied with Direction 5 provided in Decision 23848-D01-2020. The AUC approved the $7.1 million of forecast costs related to the line rebuilds in the HRFAs program of the Wildfire Mitigation Plan for the 2019-2021 test period subject to a complete prudence assessment and true-up as part of AltaLink's next opening rate base.

Directions 8 and 14

As per the AUC's instructions in directions 8 and 14, AltaLink provided an updated version of Exhibit 23848-X0321, AML Undertaking 005 Attachment (Known Violation Timelines and Mitigations Spreadsheet), to include all additional line spans that were identified with line clearance deficiencies since October 2019, and to include the additional columns that the AUC requested. Furthermore, AltaLink provided a summary of all line clearance mitigation ("LCM") program activities to March 31, 2020, including the actual number of lines mitigated and the actual LCM program expenditures, and provided an update to its LCM program forecast for 2019, 2020 and 2021.

The AUC was satisfied that AltaLink complied with directions 8 and 14 issued in Decision 23848-D01-2020. Furthermore, the AUC was satisfied that, generally, AltaLink's updated LCM program forecast, and the associated prioritization scheme and deficiency resolution timeline that AltaLink proposed in this compliance filing, appeared to reasonably balance the need to resolve a large number of clearance deficiencies with factors such as power system impacts, outage coordination, landowner and environmental requirements, and public safety. As part of AltaLink's updated prioritization scheme and deficiency resolution timeline, the AUC considered it prudent that AltaLink adjusted the number of line spans that it plans to mitigate in this test period, to focus its mitigation efforts on resolving the higher risk clearance deficiencies first. Despite this, the AUC noted that it is still concerned with the significant number of clearance deficiencies that AltaLink has identified through its LiDAR surveys and engineering assessments, as they far exceed AltaLink's historical deficiency rates. Additionally, the AUC is still concerned that the scope of the LCM program in this test period has drastically increased, as compared to previous test periods. In light of this, the AUC considered that the information being requested in directions 9, 10, 11, 12, 13, 15, and 16 from Decision 23848-D01-2020 are still necessary to assess the reasonableness of AltaLink's incremental LCM expenditures in this test period.

The AUC approved $12.1 million of AltaLink's incremental LCM program forecast, for a total LCM program expenditure of $30.9 million for the test period, but noted this $12.1 million LCM program expenditure will be subject to a complete prudence assessment and true-up as part of AltaLink's next opening rate base.

<u>AltaLink's Responses to Directions Provided in Decision 22612-D01-2018</u>

Concerning the AltaLink transfer of transmission assets to PLP and KLP and the associated Decision 22612-D01-2018, the AUC was satisfied that AltaLink complied with the requirements of directions 1, 2, 3, and 4 in this compliance filing.

PLP and KLP 2019-2021 Revenue Requirements

AltaLink stated that the approved methodology was used to develop PLP and KLP 2019-2021 revenue requirements. This methodology consists of an apportionment of the costs required to operate and maintain the assets of PLP and KLP, and according to AltaLink, it is consistent with the AUC findings of Decision 22612-D01-2018 and Decision 23848-D01-2020.

The main components of PLP and KLP 2019-2021 revenue requirements are summarized below:

Table 5. PLP 2019-2021 revenue requirement summary

Description	2019 Forecast	2020 Forecast	2021 Forecast
		($)	
Operating & maintenance (O&M)	113,350	194,314	194,314
Annual structure payments	58,155	99,695	99,695
Payments in lieu of property tax	130,292	221,054	218,764
General and administrative (G&A)	93,899	160,970	160,970
Depreciation	924,190	1,585,602	1,587,585
Return on rate base	1,713,299	2,887,806	2,806,685
Income tax expense	0	0	0
Total revenue requirement/tariff	**3,033,185**	**5,149,440**	**5,068,013**

Source: Exhibit 25627-X0012.01, Table 3.2, PDF page 3, and Exhibit 25627-X0013.01.

Table 6. KLP 2019-2021 revenue requirement summary

Description	2019 Forecast	2020 Forecast	2021 Forecast
		($)	
O&M	-	98,862	98,862
Annual structure payments	-	94,549	94,549
Payments in lieu of property tax	-	73,005	74,262
G&A	-	160,970	160,970
Depreciation	-	873,506	874,312
Return on rate base	-	1,937,099	1,891,967
Income tax expense	-	0	0
Total revenue requirement/tariff	-	**3,237,990**	**3,194,922**

Source: Exhibit 25627-X0014.01, Table 4.2, PDF page 3 and Exhibit 25627-X0015.01.

The AUC approved these requested revenue requirements.

***AMAR Developments Ltd. Interim Water Rates*, AUC Decision 25519-D01-2020**

Rates - Interim Water Rates

The AUC initiated this proceeding on May 13, 2020, based on an initial complaint from the Cambridge Park Home Owner's Association ("HOA"), regarding a water rate increase that was put into place by AMAR Developments Ltd. ("AMAR") on March 1, 2020. In this decision, the AUC considered the interim rates sought by AMAR. The AUC noted that a future decision would set final rates and make findings pertaining to the March increase.

Background

The AUC received an email on July 14, 2020, from the HOA, advising the AUC that AMAR provided notice to residents of the Cambridge Park in phases 1, 2, and 3 of a water rate adjustment. The notice indicated the following:

> As directed by the Alberta Utility Commission (AUC), AMAR Developments Ltd. has filed a rate justification on June 29th, 2020. Based on this filing the new water rates starting as of July 1, 2020 are set as follows:

Fixed Rate (per connection)	$20.00/month
Variable Usage	$5.00/m^3
Variable Over Usage	$14.50/m^3 in excess of 1.1 m^3/day

The AUC received a letter from AMAR on July 16, 2020, requesting approval of the interim rates outlined above.

<u>Applicable Legislation</u>

Pursuant to section 89(a) of the *Public Utilities Act*, the AUC may:

> … fix just and reasonable individual rates, joint rates, tolls or charges, or schedules of them, as well as commutation, mileage or kilometre rate and other special rates, which shall be imposed, observed and followed subsequently by the owner of the public utility;

<u>Details Supporting Interim Rates</u>

Water Usage and Supply

The AUC noted that the monthly water use per home in Cambridge Park spikes to over 30 m^3 per month during the summer. Further on a four-year basis, the annual usage is 34.2 m^3 per month with summer usage of 40.8 m^3 per month. The AUC noted that typical annual water usage in Alberta is approximately 20 m^3 per month. Given the significant volumes of water being consumed in Cambridge Park, the AUC considered this level of water usage may place a strain on the ability of AMAR to supply water at current rates.

AMAR indicated that the authorized maximum daily water diversions it may draw from well #1 and well #2 is 230 m^3/day. Given the demand placed on the water system, and the physical limitation of the wells, the water supply from the wells has been inadequate to supply the needs of the Cambridge Park development. These shortfalls have necessitated periodic hauling of water from offsite to ensure an uninterrupted supply of water to Cambridge Park. The AUC noted AMAR reported water hauling costs of $12,599 in 2018, $70,649 in 2019, and has forecast water hauling costs of $163,200 in 2020. Using historic costs, AMAR calculated the cost of hauled water at $20.40/m^3. Based on its forecast water hauling costs in 2020, the AUC was of the view this may place an undue strain on AMAR, thereby justifying increased rates to allow AMAR to continue to provide a safe and reliable supply of water to its residents.

Revenue Requirement

Based on the revenue requirement amounts proposed by AMAR, and based on the revenues it collected in 2018 and 2019, the AUC noted that AMAR stated that it experienced respective revenue shortfalls of $67,923 and $36,949.7 The AUC considered that these amounts, on their face, were material and justified the need for increased rates.

2020 Rates and Revenue Requirement

Based on an observed increased water usage of eight percent from January to April 2020, and 12 percent for May 2020, AMAR proposed a demand rate of $5.00/m^3 and as an additional incentive, a stepped rate of $14.50/m^3 for water usage in excess of 1.1 m^3/day on average. These rates were selected in an attempt to remain revenue-neutral and encourage conservation.

The AUC noted that based on AMAR's proposed 2020 revenue requirement of $426,738, the proposed rates in 2020 would result in revenues of $425,832.8 The AUC found that the proposed rates would result in AMAR essentially breaking even in 2020 on a forecast basis. Based on this information, the AUC considered the proposed rates to be reasonable on an interim basis.

Approval of Interim Rates

The AUC noted that it may approve rates on an interim basis prior to making a final decision on rates. If the rate that is finally approved is different from the interim rate, an adjustment is made to recover or refund the difference from customers between the amounts paid on the interim rate and the amounts that would have been paid during that time if final rates had been in place.

In Decision 2005-099, the AUC set out some general principles in considering interim rate increases. The AUC explained that these principles can be grouped into two categories:

1) those that relate to the quantum of and need for the rate increase; and

2) those that relate to more general public interest considerations.

Regarding principles related to the quantum and need for the rate increase, the AUC found that there was an immediate need for a rate increase. In particular, the AUC noted that the water usage and supply issues, and revenue requirement issues suggest that without approval to charge increased rates, the financial integrity of AMAR may not be preserved. The AUC stated that, if AMAR lacks financial stability, the AUC questions whether AMAR will be able to continue safe utility operations without an interim rate adjustment. Further, based on the information provided by AMAR, the AUC found that the identified revenue deficiency would be probable and material. On this basis, the AUC considered that it should approve an interim rate increase for AMAR, for customers to continue to receive safe and reliable service.

Regarding public interest considerations, the AUC noted that the tiered rate proposed by AMAR was designed to send a price signal to those households that use over 1.1 m^3/day on average of the significant increase in costs placed on the system to provide significant volumes of water. Given the evidence provided by AMAR, the AUC found the tiered rate to be reasonable. Further, the AUC considered that it was imperative on a public interest consideration to provide water rates that allow the utility to continue to provide service. In the absence of sufficient rates to cover the costs of providing safe and reliable service, homeowners would be left to securing their own supply of water. In such circumstances, one option would be for homeowners to place individual water tanks and necessary plumbing on their property and have water delivered at their own expense. In the AUC's experience, such a situation does not serve the public interest. It is more cost-effective, safe and reliable to approve an increase in rates than to have service discontinued. On this basis, the AUC found that the proposed interim water rate increase was reasonable.

Order

The AUC order that AMAR Developments Ltd. water rates effective July 17, 2020, on an interim refundable basis shall be:

Fixed Rate (per connection)	\$20.00/month
Variable Usage	\$5.00/m^3
Variable Over Usage	\$14.50/m^3 in excess of 1.1 m^3/day average over month

***ATCO Electric Ltd. 2019 Distribution Tariff Phase II Compliance Filing*, AUC Decision 25645-D01-2020**
Rates - Compliance Filing

In this decision the AUC considered ATCO Electric Ltd. ("ATCO Electric")'s compliance with the AUC's directions issued in Decision 24747-D01-2020 regarding ATCO Electric's 2019 Distribution Tariff Phase II. The AUC found that ATCO Electric complied with the AUC's directions. However, the AUC did not accept ATCO Electric's proposed revisions to section 15.1 of the customer terms and conditions for electric distribution service ("T&Cs"). In the interest of regulatory efficiency, the AUC made certain revisions to section 15.1 of ATCO Electric's customer T&Cs and approved them effective August 1, 2020.

Background

On April 30, 2020, the AUC issued Decision 24747-D01-2020, regarding ATCO Electric's 2019 Distribution Tariff Phase II Application. The decision ordered ATCO Electric to file a compliance filing by June 11, 2020, and include revised T&Cs, updated cost-of-service studies ("COSS") and tariff design schedules, price schedules, and billing impact schedules that reflect the findings, directions, and conclusions in that decision.

On June 4, 2020, ATCO Electric submitted its compliance filing with the AUC requesting approval of its proposed distribution tariffs and customer and retailer T&Cs, effective August 1, 2020.

Compliance with AUC Directions

In Decision 24747-D01-2020, the AUC issued 20 directions. ATCO Electric confirmed that directions 4, 6, 11, and 16 would be addressed in its next Phase II application, that Direction 17 would be addressed in its future maintenance multiplier applications, and that Direction 20 would be addressed in its 2021 annual performance-based regulation ("PBR") rate adjustment filing. ATCO Electric provided its responses to the remaining 14 directions and filed schedules that included the directed adjustments, updated T&Cs, and information required to demonstrate compliance with the AUC's directions.

Cost-of-Service Study and Tariff Design Adjustments

In Decision 24747-D01-2020, the AUC directed ATCO Electric to make certain changes to its brushing and wholesale billing studies and reflect the changes in its 2017 COSS. The AUC also directed ATCO Electric to make certain adjustments to the tariff design schedules, including the removal of the proposed low-use residential rate class D12, and to submit updated bill impact schedules, rate calculations schedules, and price schedules. ATCO Electric provided updated 2017 COSS schedules and tariff design schedules, as well as updated bill impact schedules, rate calculation, and price schedules effective August 1, 2020, to reflect the AUC directions in Decision 24747-D01-2020.

The AUC issued Direction 1 regarding the use of an incorrect allocator in its brushing study. ATCO Electric stated that it corrected the brushing study to incorporate mid-year gross plant as the allocator for brushing costs and provided a table comparing the allocation of brushing costs as submitted in the original proceeding (Proceeding 24747) and the current compliance filing. The AUC was satisfied that ATCO Electric used the correct allocator, the mid-year gross plant, for brushing costs in compliance with Direction 1.

At paragraph 78 of Decision 24747-D01-2020, the AUC issued Direction 2, directing ATCO Electric, in the compliance filing to that decision, to update its wholesale billing study. ATCO Electric stated that it revised its wholesale billing study to reflect changes resulting from the Master Service Agreement ("MSA") rates approved in Decision 20514-D02-2019 and any related compliance filings. The AUC reviewed the revised schedules provided by ATCO Electric showing how it revised its wholesale billing study to apply changes resulting from MSA rates approved in Decision 20514-D02-2019 and any related compliance filings and was satisfied that the approved MSA rates were incorporated correctly.

In Decision 24747-D01-2020, the AUC was not convinced that a new rate for low-use customers was warranted at that time, and at paragraph 162 of that decision, the AUC denied the proposed low-use residential rate class D12 and directed ATCO Electric to remove the proposed low-use residential rate class D12 from its rate design (Direction 3). The AUC was satisfied that ATCO Electric correctly removed the proposed low-use residential rate class D12 from its rate design.

At paragraph 181 of Decision 24747-D01-2020, the AUC approved the small technology rate class D22 and issued Direction 5 to ATCO Electric:

> … to incorporate the amended availability clause "Available to Small Technology services with predictable energy consumption as determined by the Company" which ATCO Electric included in its response to the UCA [Office of the Utilities Consumer Advocate] IR, into its rate sheet for Price Schedule D22 for the small technology rate.

The AUC was satisfied that ATCO Electric incorporated the amended availability clause presented in the quote above into its rate sheet for Price Schedule D22.

At paragraph 195 of Decision 24747-D01-2020, the AUC noted ATCO Electric's commitment to provide updated bill impact schedules and issued Direction 7 to ATCO Electric:

> … to submit updated bill impact schedules comparing the proposed 2020 rates, as adjusted to reflect the Commission's findings and directions in this decision, to the 2020 rates that would have resulted absent the 2017 COSS.

The AUC found that ATCO Electric adjusted its proposed 2020 rates to reflect the AUC's findings and directions and compared them to the 2020 rates that would have resulted absent the 2017 COSS.

The AUC stated that it had reviewed the schedules and calculations used to determine ATCO Electric's proposed 2019 PBR rates and found the methodology adequately reflected the AUC determinations in Decision 22394-D01-2018 and Decision 2012-237, and that the proposal was acceptable. Accordingly, the AUC approved the methodology proposed by ATCO Electric to adjust its rates through to the applicable year of implementation and issued Direction 8 which required the provision of updated calculation schedules and price schedules. The AUC was satisfied that the adjustments were done correctly, and therefore found that ATCO Electric complied with Direction 8.

Terms and Conditions

The AUC denied ATCO Electric's proposed changes to its customer T&Cs related to the transmission payment in lieu of notice ("PILON"), except for the amendments to section 15.2(b), and issued Direction 9 for ATCO Electric to "… reflect the Commission's findings with respect to PILON and additional transmission-related exit costs in its customer T&Cs, in its compliance filing to this decision." It also issued Direction 10 for ATCO Electric to remove any proposed changes to its T&Cs that are related to its distribution PILON. The AUC was satisfied that ATCO Electric removed the proposed changes to its customer T&Cs related to transmission PILON, additional transmission-related exit costs and distribution PILON in compliance with directions 9 and 10.

At paragraph 247 of Decision 24747-D01-2020, the AUC determined that clarification at section 15.1 of ATCO Electric's customer T&Cs was required to define when ATCO Electric considers a contract termination proposal to be accepted by a customer and issued Direction 12 for ATCO Electric to:

> … revise Section 15.1(e) to clarify the circumstances of when "a contract termination proposal is accepted by the Customer" and how ATCO Electric will determine when this termination proposal is considered accepted. Accordingly, the Commission directs ATCO Electric to clarify the circumstances of when and in what circumstances "a contract termination proposal is accepted by the Customer." As such, the Commission directs ATCO Electric, in its compliance filing to this decision, to propose amendments to Section 15.1 to account for the Commission's findings in this paragraph and in Section 9.1.1.1, and to add a definition for "buy-down," with any supporting references to its Customer Guide to New Extensions.

The AUC reviewed section 15.1 of the updated customer T&Cs provided by ATCO Electric and found that the revisions proposed by ATCO Electric did not adequately clarify when and in what circumstances a contract termination proposal is accepted by a customer and how ATCO Electric will determine when this termination proposal is considered accepted. As such, the AUC made the revisions to section 15.1 of ATCO Electric's customer T&Cs.

At paragraph 262 of Decision 24747-D01-2020, the AUC denied ATCO Electric's proposed addition of "for any other reason deemed necessary by the Company" to section 4.4 of its customer T&Cs, which lists the circumstances where ATCO Electric may reject an applicant's request for a service connection. Accordingly, the AUC issued Direction 14 for ATCO Electric to remove the proposed amendments to section 4.4(h) of its customer T&Cs. The AUC reviewed section 4.4 of the updated customer T&Cs and observed that the section 4.4(h) amendment had been removed in compliance with Direction 14.

At paragraph 270 of Decision 24747-D01-2020, the AUC determined that separating the Available Company Investment and Supplementary Service Charges schedules from ATCO Electric's terms and conditions for electric distribution service would provide a higher degree of transparency and afford those customers requiring this information a higher degree of access. Accordingly, the AUC issued Direction 15 to ATCO Electric to file its Available Company Investment and Supplementary Service Charges schedules as separate documents in its future annual PBR rate adjustment applications.

ATCO Electric provided stand-alone schedules of Available Company Investment and Supplementary Service Charges in attachments 7-6 and 7-7,33 and noted that it would file copies of the stand-alone schedules in future annual PBR rate adjustment applications. The AUC approved ATCO Electric's customer and retailer T&Cs, and the stand-alone schedules of Available Company Investment and Supplementary Service Charges.

In Decision 24747-D01-2020, the AUC provided certain directions regarding Rider E services. The AUC agreed with ATCO Electric that given the nature of the Rider E services, Rider E should not form part of ATCO Electric's AUC-approved rates and the pursuit of amending contractual arrangements with Rider E customers as an unregulated service should continue. Accordingly, the AUC issued Direction 18 to ATCO Electric to pursue the timely execution of contractual amendments with remaining Rider E customers, in order to remove their services from regulated service under Rider E and adopt unregulated private contracts. ATCO Electric confirmed that it would pursue the timely execution of contractual amendments with Rider E customers as directed by the AUC.

At paragraph 284 of Decision 24747-D01-2020, the AUC stated that it would expect ATCO Electric to execute any contractual amendments to remove the remaining customer services from regulated service under Rider E by December 31, 2021 and issued Direction 19 to ATCO Electric to confirm any restrictions that would impede it achieving this outcome by that deadline, in the compliance filing to this decision.

ATCO Electric confirmed that it did not foresee any restrictions. The AUC accepted ATCO Electric's responses to directions 18 and 19 and found that ATCO Electric complied with these AUC directions.

<u>Order</u>

The AUC ordered that ATCO Electric Ltd.'s 2019 Distribution Tariff Phase II cost-of-service study and tariff design was approved.

***ATCO Electric Ltd. 2018-2019 General Tariff Application Compliance Filing – Information Technology Common Matters*, AUC Decision 24805-D01-2020**

Rates - Information Technology Compliance Filing

In this decision, the AUC considered the compliance of ATCO Electric Ltd. ("ATCO Electric") with Decision 20514-D02-2019 ("IT Common Matters Decision"), for information technology common matters and the associated costs. This decision refers to both ATCO Electric and to ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. (referred to as "AP"), the two transmission utilities that were the subject of the IT Common Matters Decision. The AUC collectively referred to ATCO Electric and AP as the "ATCO Transmission Utilities". A separate decision was concurrently issued by the AUC for AP in Proceeding 24817. In this decision, the AUC approved the majority of ATCO Electric's IT common matters compliance application but noted that there are outstanding items that will require a second compliance filing.

The AUC noted that ATCO Gas, a division of ATCO Gas and Pipelines Ltd., and ATCO Electric's distribution function also incur IT common matters costs, which will be addressed separately under performance-based regulation ("PBR"). The distribution utilities were referred to as the "ATCO Distribution Utilities" in this decision.

<u>Background</u>

In the IT Common Matters Decision, the ATCO Transmission Utilities were directed to apply:

(a) a reduction of 13 percent in pricing in year one (2015) of the master service agreements ("MSAs"); and

(b) a glide path that reduces prices on a weighted average across towers by 4.61 per cent in each of years two through 10 of the MSAs, as approved by the AUC.

The ATCO Transmission Utilities were directed to file their compliance applications to the IT Common Matters Decision in the compliance filings to their general rate application (“GRA”) or general tariff application (“GTA”). Separate directions were issued for the ATCO Distribution Utilities.

In Proceeding 24817 and Proceeding 24805, the AUC noted that it had to determine whether AP and ATCO Electric, respectively, have complied with the findings and directions issued by the AUC in Decision 23793-D01-2019, Decision 22742-D01-2019, Decision 22742-D02-2019, and the IT Common Matters Decision.

Directions Related to IT Common Matters Costs

In accordance with directions 1 and 4 of the IT Common Matters Decision, the ATCO Transmission Utilities provided schedules referencing the placeholder dollars for capital, indirect capital, and operations and maintenance from the previous GTA proceedings on a total dollar basis per annum. The schedules included in ATCO Electric’s compliance filing detailed the first-year pricing reduction of 13 per cent and glide path reductions, which were calculated as the difference between the 4.61 per cent as approved in the IT Common Matters Decision and the average glide path set out in the MSA.

While the IT Common Matters Decision did not require a line-by-line or tower-by-tower assessment, the ATCO Transmission Utilities submitted an alternative approach to their original IT placeholder adjustment. In a supplementary filing, the ATCO Transmission Utilities provided a detailed back-up for a Service ID-by-Service ID analysis, which applied the 13 per cent reduction on the first-year pricing and the 4.61 per cent glide path for years two to 10 to the individual Service IDs and approved volumes.

Placeholders

In the IT Common Matters Decision, the AUC noted that it approved an adjustment to IT rates on a weighted average tower basis. The AUC was of the view that the placeholder adjustment, when compared with the detailed line-by-line adjustment resulted in the same refund amounts. It further noted that the more detailed line-by-line Service ID approach offers greater transparency into how the ATCO Transmission Utilities applied the first-year pricing reduction of 13 per cent and the 4.61 per cent glide path to years two to 10 of the MSA prices. The AUC found that, in the circumstances, the variance between the two methods was not material. However, the AUC was mindful of its comments in the IT Common Matters Decision, regarding placeholders and the finalization of IT rates and revenue requirement, which are reproduced below:

> The approved IT rates will be multiplied by utility-specific IT volumes to determine costs that will be approved for inclusion in revenue requirement in a future rate proceeding. The IT costs for each of the ATCO Utilities will then be finalized and included in revenue requirement and rates.

The AUC was of the view that to properly assess adjustments to IT placeholders the ATCO Transmission Utilities must show their adjustments to MSA rates based on the IT rates being multiplied by volumes and the resulting adjustments to IT placeholders. The AUC considered that the proposed adjustment to IT rates by applying the 13 per cent first-year reduction and the 4.61 per cent glide path thereafter to the placeholder rate or dollar value was reasonable for Service IDs not traced to the price schedules or where the Service ID is not volume-based.

Custom Unit Rates and New Services

Interveners made submissions regarding custom unit rates and new services. The AUC noted that in the IT Common Matters Decision, it did not provide any specific direction on these issues. The ATCO Transmission Utilities stated that they applied the IT common matters directions to the placeholder dollar amounts for custom rates, consistent with past decisions related to truing-up placeholder costs. The AUC found that the ATCO Transmission Utilities’ proposed IT adjustments to custom unit rates demonstrated a reasonable approach, and accepted the ATCO Transmission Utilities’ method to adjust custom unit rates, as filed.

With regard to new services, the AUC accepted that new services may be required over the term of the MSA and similar to custom unit rates, the ATCO Transmission Utilities' approach of applying a 13 per cent adjustment in year one and then a glide path adjustment for years two to 10 from the date service begins is reasonable to account for new services, and complies with the AUC's general Direction 1 of the IT Common Matters Decision.

True-up for Capital Amounts for 2018 and 2019

Interveners submitted that the ATCO Transmission Utilities did not include adjustments to property, plant, and equipment ("PP&E") to account for actual amounts for direct capital and other capital and the impacts of those adjustments with respect to 2018 and 2019.

The AUC accepted the ATCO Transmission Utilities' explanation that the true-up of non-IT rate base items in the original AP and ATCO Electric GRA/GTA proceedings included actual amounts up to 2017. The AUC noted that for ATCO Electric, capital true-up of 2018 and 2019 should be addressed in ATCO Electric's next GTA.

Opening Rate Base and Accumulated Depreciation

The AUC found that the ATCO Transmission Utilities calculated the rate base adjustments, and depreciation amounts to be refunded or collected, in a manner consistent with Decision 3378-D01-2016. However, unlike Decision 3378-D01-2016, which calculated placeholder and actual adjustments to prior GRA or GTA revenue requirement periods, the IT Common Matters Decision affects prior periods, current periods, and future GRA and GTA test periods.

The AUC noted that IT service volumes for AP's 2019-2020 GRA and ATCO Electric's 2018-2019 GTA (subject to any adjusted full-time equivalent amounts) were approved in decisions 23793-D01-2019 and 22742-D01-2019, respectively, and were to be adjusted by the revised IT services pricing approved in the IT Common Matters Decision. The AUC found that ATCO Transmission Utilities did not comply with those directions provided in Decision 23793-D01-2019 and Decision 22742-D01-2019 to reflect changes relating to the IT Common Matters Decision. To ensure that the proper adjustments are made in accordance with previous compliance filing directions, and for consistency amongst the ATCO Transmission Utilities, the AUC directed the ATCO Transmission Utilities to provide additional information in their second compliance filing MFR schedules.

Tax Deductions

The AUC noted that ATCO Electric has a tax deferral account should a tax rate change in the future. It further noted that ATCO Electric did not include the refund of previously collected future income tax in its calculated refund amounts to customers. ATCO Electric calculated future income tax ("FIT") expenses as part of its 2015, 2016, and 2017 revenue requirements. As explained by ATCO Electric, FIT is calculated based on forecast tax inputs (e.g., capital cost allowance, depreciation, and "running costs"). These inputs included IT costs, which were adjusted in response to the IT Common Matters Decision. As a result, the amount of FIT that was collected for 2015, 2016, and 2017 should also be adjusted for the change in the tax inputs. ATCO Electric estimated that a total of $0.5 million of FIT was over-collected for the years 2015 to 2017 as a result of tax inputs being adjusted to comply with the IT Common Matters Decision. ATCO Electric was directed to refund the FIT amounts for the years 2015, 2016, and 2017 that it should not have collected from customers as a result of its adjusted IT costs. ATCO Electric was also directed to reflect the effects of the 2018 and 2019 test period adjustments in its corresponding MFR schedules.

Carrying Costs

The AUC noted that it has the discretion to apply Rule 023 or the weighted average cost of capital ("WACC") in the individual circumstances that are applicable to a GRA or GTA. Consistent with the method used in Decision 3378-D01-2016, which is the most recent IT common matters decision that applied interest for carrying costs, the AUC found that WACC should be used when calculating interest on IT refund balances.

The AUC directed the ATCO Transmission Utilities to recalculate the balances using its WACC as the interest rate applied to carrying costs, and to file the resulting refund and regulatory schedules for ATCO Electric and AP in the compliance filing to this decision.

Net Present Value ("NPV")

Although the NPV method was used in some prior decisions, the AUC considered that whenever possible, costs should be removed from rate base consistent with the method traditionally applied to PP&E - capital project disallowances. The AUC directed the ATCO Transmission Utilities to remove all IT directed adjustments to direct and indirect capital from rate base in compliance with the IT Common Matters Decision in the compliance filing to this decision and future IT common matters, GRA, GTA, or other relevant transmission proceedings and compliance proceedings.

A determination of how the ATCO Distribution Utilities apply their directed IT adjustments or disallowances from the IT Common Matters Decision is a matter to be determined at the relevant PBR-related proceeding or proceedings. In this decision, the AUC did not evaluate the NPV methodology as it would apply to either of the ATCO Distribution Utilities under the PBR framework.

Future Rate Proceedings

As the ATCO Transmission Utilities provided both placeholder and detailed line-by-line adjustments in the current proceedings, the AUC considered that populating Excel worksheets with forecast and actual volumes, new services, and approved IT rates in future proceedings, should not be overly burdensome. For future rate applications, the AUC directed the ATCO Transmission Utilities to provide such information, to comply with directions from the IT Common Matters Decision and this decision.

Order

ATCO Electric was directed to file a second compliance filing in accordance with the findings and directions in this decision.

ATCO Electric Ltd. Stage 2 Review and Variance of Decision 22742-D01-2019 - ATCO Electric Ltd. 2018-2019 Transmission General Tariff Application, **AUC Decision 25282-D01-2020**
Review and Variance - Rates - Allocation of System Costs

Decision Summary

In this decision, the AUC determined whether to confirm, rescind or vary Decision 22742-D01-20191 ("Decision") on ATCO Electric Ltd.'s ("ATCO Electric") 2018-2019 transmission general tariff application ("GTA") relating to two specific issues: (a) the allocation of transmission line 9L101 ("Kearl Line") relocation costs; and (b) the amount of square footage attributable to corporate and head office employees in ATCO Park for purposes of determining head office rent costs.

The AUC decided to (a) vary Decision 22742-D01-2019 as it relates to the allocation of Kearl Line relocation costs and granted ATCO Electric's request to treat the costs associated with the relocation of Kearl Line as a system cost; and (b) vary the square footage of ATCO Park applied to the ratio used to calculate the allocation of head office rent costs to ATCO Electric to 200,000 square feet (sq. ft.), instead of the 155,000 sq. ft. directed by the hearing panel in Decision 22742-D01-2019.

Introduction

On July 4, 2019, the AUC issued the Decision, which addressed the reasonableness of ATCO Electric's forecast revenue requirements for the 2018-2019 test period. On August 19, 2019, ATCO Electric filed a review and variance ("R&V") application requesting that the AUC review specific findings in the Decision. On January 9, 2020, the AUC issued Decision 24824-D01-2020, granting the second stage review proceeding.

In this decision, the members of the AUC panel who authored the Decision are referred to as the Hearing Panel, the members of the AUC panel who authored Decision 24824-D01-2020, granting a second stage R&V proceeding are referred to as the Stage 1 Panel, and the members of the AUC panel considering the current second stage R&V submissions are referred to as the Stage 2 Panel.

The AUC's Review Process

The AUC's authority to review its own decisions is discretionary and is found in section 10 of the *Alberta Utilities Commission Act*. That section authorizes the AUC to make rules governing its review process and the AUC established Rule 016 under that authority. The review process typically has two stages. In the first stage, a review panel must decide whether there are grounds to review the original decision. This is sometimes referred to as the "preliminary question." If the review panel decides that there are grounds to review the decision, the AUC's proceeds to the second stage of the process with a hearing or other proceeding to decide whether to confirm, vary or rescind the original decision. This decision addresses the second stage of the R&V process.

Allocation of Kearl Line Relocation Costs

In Proceeding 22742, ATCO Electric requested confirmation that the forecast costs associated with relocating the Kearl Line, as requested by Fort Hills Energy LP to accommodate its oil sands expansion project, be allocated by ATCO Electric as system costs rather than as direct customer costs payable by the mine owner. The Hearing Panel determined that the proposed Kearl Line relocation costs were the responsibility of the mine owner. In this Stage 2 proceeding, ATCO Electric submitted that the Decision should be materially varied to allocate Kearl Line relocation costs as system costs.

2003 Relocation Principles

The relocation principles contained in Decision 2003-043 and the treatment of these principles for the purposes of allocating Kearl Line relocation costs arose as an issue in the Decision and the current proceeding. Decision 2003-043 was issued by the AUC's predecessor, the Alberta Energy and Utilities Board ("Board"). The Board set out broad principles to generally guide the board's assessment of cost responsibility for the relocation of transmission lines ("2003 Relocation Principles"). The Board also expressed that the principles could assist parties in coming to commercial agreements, should they so desire.

The 2003 Relocation Principles are as follows:

- The Board must be satisfied as to the balance between the public interest and the interest of any affected party.
- The sterilization of mineable ore, and direct and unavoidable conflict with the infrastructure and development required to mine the ore, is a reasonable cause for the relocation of a transmission line.
- A valid mineral lease and an applied for/approved mine plan should exist at the time the move is requested.
- The Transmission Administrator's customers should be required to incur relocation costs, as a system cost, when there is a reasonable cause to move a system transmission line, provided that:
    - A valid mineral lease existed prior to the construction of the transmission line;
    - A practical alternative route is available; and
    - There are no unusual negative impacts on the AIES [Alberta Interconnected Electric System] that cannot be reasonably addressed.

The cost of relocating a ***local*** transmission line required to serve the party requesting the relocation should be the responsibility of that party. [emphasis in original]

Stage 2 Panel Findings

The Stage 2 Panel considered that the 2003 Relocation Principles were not intended to be determinative of responsibility for relocation costs, or to displace the AUC's consideration of the specific facts and circumstances relevant to the application before it, or of principles other than those articulated in the 2003 Relocation Principles. In the context of this proceeding, the Stage 2 Panel found that the general guidance provided by the 2003 Relocation Principles served as a helpful framework to guide its analysis. However, adherence to the 2003 Relocation Principles cannot constrain the AUC's broad public interest discretion under the provisions of the *Hydro and Electric Energy Act* to provide for the payment of compensation related to transmission line relocations, including determining whether compensation is warranted and to whom.

Although the Stage 2 Panel determined that it was not bound by 2003 Relocation Principles, it stated that it was noteworthy that the first of the principles posit a broad public interest review in allocating the costs of a transmission line relocation, as follows:

> The Board must be satisfied as to the balance between the public interest and the interest of any affected party.

The Stage 2 Panel found that it must ultimately weigh the costs to ratepayers against the benefits of the line relocation, including any benefits associated with avoided sterilization of mineable ore and that this weighing exercise may invoke considerations beyond the enumeration provided in the 2003 Relocation Principles.

The Stage 2 Panel re-examined the issue of allocating Kearl Line relocation costs and found that it was in the public interest to vary the treatment of Kearl Line relocation costs to a system cost. It determined that the Kearl Line is required to be relocated to allow for the recovery of the mineable ore underlying it. The Stage 2 Panel also weighed the relocation costs relative to the public interest benefits associated with relocating the line. In the circumstances of this case, the Stage 2 Panel determined that the benefits of relocating the Kearl Line outweigh the costs associated therewith. Finally, the Stage 2 Panel determined that, in this case, price signals are not a relevant factor in examining how to allocate Kearl Line relocation costs in the public interest. This is because the requirement to relocate the line was not discretionary to the mine owner as a result of legislative and regulatory requirements, including one of the stated purposes of the *Oil Sands Conservation Act* which is "to ensure orderly, efficient and economical development in the public interest of the oil sands resources of Alberta."

The Stage 2 Panel noted that the AUC provided the AESO with direction to review the 2003 Relocation Principles in its next general tariff application. It further noted that nothing in this decision on the Kearl Line relocation precludes any future determinations of the AUC on the principles that should apply to line relocations and the associated costs.

Square Footage of ATCO Park Used in Allocation of Head Office Rent Costs

In Proceeding 22742, ATCO Electric forecast recovery of head office rent costs for the 2018 and 2019 test years. ATCO Electric had forecast its allocated costs to increase as a result of the ATCO Group's move to a new corporate head office campus in southwest Calgary called ATCO Park, from its previous downtown location called ATCO Centre.

In its assessment of the allocation of head office rent costs, the Hearing Panel indicated that it had concerns concerning the excess capacity at ATCO Park beyond what it said was reasonably required for office space for current employees and common spaces. The Hearing Panel directed ATCO Electric to adjust the amount of head office rent recoverable in its revenue requirement, as follows:

> 680. Therefore, to adjust the number of employees used in the allocation of corporate staff, and to ensure AET's [ATCO Electric Transmission] regulated customers are not charged for the capacity of 100 staff identified above, AET is directed to compute the square footage in its allocation of corporate rent for ATCO Park on the basis of (260/600) x 21 per cent …

The Stage 2 Panel noted that the (260/600) x 21 per cent formula (the "Proration Formula") represented the ratio of head office employees to total employee capacity at ATCO Park. The Proration Formula was used to adjust for the excess employee capacity of approximately 100 employees at ATCO Park.

In its Stage 2 R&V submission, ATCO Electric submitted that the Hearing Panel made an error of fact when finding that the total square footage of ATCO Park was 155,000 sq. ft., and explained that the reference to 155,000 sq. ft. in its original application was the space occupied by ATCO head office staff, which corresponds to floors one through four of the west tower and floor one of the east tower of ATCO Park, not to the entirety of ATCO Park.

In its Stage 1 R&V application, ATCO Electric submitted that the total square footage of ATCO Park was approximately 246,000 sq. ft., and in its Stage 2 R&V evidence, ATCO Electric provided a certificate of area from a third-party building measurement company confirming that the total square footage of ATCO Park is 248,743 sq. ft. ATCO Electric submitted that to correct the head office rent allocation error in the Decision, its revenue requirements should be increased by $664,020 and $673,242 in each of 2018 and in 2019, respectively.

The Stage 2 Panel considered it reasonable to apply the ratio from the Proration Formula, (260/600) x 21 per cent, to the initially projected 200,000 sq. ft. to calculate the allocation of head office rent costs to ATCO Electric, rather than applying the formula to the entire square footage of ATCO Park (248,743 sq. ft.) as suggested by ATCO Electric in its Stage 2 R&V submissions, or to the 155,000 sq. ft. as directed by the Hearing Panel in the Decision. Using this allocation methodology, ATCO Electric's revenue requirement was increased by $147,370 in 2018 and by $149,416 in 2019.

The Stage 2 Panel directed ATCO Electric to provide adequate supporting information in future GTAs to justify the square footage attributed to head office staff, and to clearly explain the usage and necessity of the common space included at ATCO Park and attributable to ATCO Electric.

***ATCO Gas, a Division of ATCO Gas and Pipelines Ltd. 2020 Transmission Service Charge Update (Rider T)*, AUC Decision 25646-D01-2020**

Rates - Transmission Service Charge Update

In this decision, the AUC considered an application from ATCO Gas requesting approval of an update to its 2020 transmission service charge rider ("Rider T") rates, effective August 1, 2020. The AUC approved the updated Rider T rates.

Background

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

AUC Findings

Cross-Subsidization Between North and South Customers

In Decision 2014-062, the AUC approved the implementation of a province-wide Rider T rate to replace the previous practice of maintaining separate Rider T rates for ATCO Gas's north and south service territories. In successive ATCO Gas Rider T decisions subsequent to Decision 2014-062, the AUC required ATCO Gas to provide analyses to assist the AUC to assess whether there was substantial cross-subsidization between north and south customers as a result of the province-wide implementation of a Rider T rate.

In the current application, ATCO Gas provided the following table setting out the differences between the proposed province-wide rates and the rates that would have resulted if calculated separately for north and south customers.

Table 1. Cross-subsidization analysis[19]

Rate group	Province-wide rate	North		South	
		Rate	Difference	Rate	Difference
	($/GJ)				
Low	0.895	0.915	0.020	0.873	(0.022)
Mid	0.820	0.828	0.008	0.807	(0.013)
High	0.245	0.275	0.030	0.217	(0.028)

ATCO Gas's analysis showed that, under province-wide Rider T rates, as compared to having separate rates for north and south, a typical (low-use) residential customer in the south would see a $0.99 decrease in their annual bill and a typical (low-use) residential customer in the north would see a corresponding increase of $0.90 due to differences in billing determinants and CDQ. The AUC found that this level of cross-subsidization was not significant enough to justify having separate rates for north and south, and was consistent with the AUC's acceptance of similar minimal cross-subsidization in prior decisions approving ATCO Gas's Rider T.

Rider T Rates and Bill Impacts

The following table sets out a comparison of the current and proposed rates for each of ATCO Gas's rate groups:

Table 2. ATCO Gas Rider T[22]

Rate group	Existing Rider T	Proposed new Rider T
	($)	
Low Use (per GJ)	0.762	0.895
Mid Use (per GJ)	0.696	0.820
High Use (per day of GJ demand)	0.210	0.245

ATCO Gas explained that, assuming an implementation date of August 1, 2020, the total annual charges for a residential (low-use) customer in the south service territory that utilizes 115 GJ annually would see an increase to $702 from $696, and a similar residential customer in the north service territory would see an increase to $742 from $736. 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 found that the estimated rate impact of the August 1, 2020, Rider T was reasonable for all rate classes. The AUC stated that the implementation of the updated 2020 Rider T results in rate increases for all three rate groups, for both ATCO Gas North and ATCO Gas South.

The AUC approved the proposed new Rider T rates set out in Table 2. The AUC stated that the approved Rider T rates would remain in place until otherwise directed by the AUC.

***ATCO Pipelines, a Division of ATCO Gas and Pipelines Ltd. 2019-2020 General Rate Application Compliance Filing*, AUC Decision 24817-D01-2020**

Rates - Compliance Filing

In this decision, the AUC considered an application filed by ATCO Pipelines ("AP"), a division of ATCO Gas and Pipelines Ltd., requesting approval of its compliance filing to Decision 23793-D01-2019, for AP's 2019-2020 general rate application ("GRA"). This decision also addressed compliance with Decision 20514-D02-2019 ("IT Common Matters Decision"), for information technology common matters and the associated costs to ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. A separate IT Common Matters Decision was concurrently issued by the AUC for ATCO Electric Ltd.'s transmission function in Proceeding 24805. The AUC approved the majority of AP's compliance application but there were outstanding items that will require a second compliance filing.

Introduction

AP applied with the AUC on August 15, 2019, requesting approval of its compliance filing to Decision 23793-D01-2019, AP's 2019-2020 GRA. In its application for approval of its transmission revenue requirement in the compliance filing, AP requested the AUC's approval or confirmation of:

- The 2019 forecast revenue requirement of $274,530,000 and its 2020 forecast revenue requirements of $304,730,000 as final, subject to any placeholders;
- The finalization of all outstanding 2019 and 2020 reserve accounts and deferral accounts;
- The disposition of the information and technology costs and 2018 generic cost of capital ("GCOC") placeholders; and
- Its compliance with directions given in previous decisions.

Concerning the GCOC placeholders beyond 2018, AP noted that the equity thickness and return on equity placeholders for 2019 and 2020 included in the GRA were equivalent to the percentages approved in Decision 22570-D01-2018.

Background

In the IT Common Matters Decision, the ATCO Transmission Utilities (AP and ATCO Electric Ltd. for its transmission function, referred to as "ATCO Electric") were directed to apply (i) a reduction of 13 per cent in pricing in year one (2015) of the master service agreements ("MSAs"); and (ii) a glide path that reduces prices on a weighted average across towers by 4.61 per cent in each of years two through 10 of the MSAs. The ATCO Transmission Utilities were directed to file their compliance applications to the IT Common Matters Decision in the compliance filings to their GRA or general tariff application ("GTA"). Separate directions were issued for ATCO Gas – Distribution, and ATCO Electric – Distribution ("ATCO Distribution Utilities").

AP's GRA decision, Decision 23793-D01-2019, included its proposed revenue requirement for 2019-2020. The AUC approved AP's 2018 opening rate base on an actual basis. In the decision, the AUC gave further directions on 2018 closing rate base, 2019 opening rate base and other substantive matters to be addressed in this compliance filing or future GRAs. The AUC directed, with respect to one of AP's facilities projects, the Pembina-Keephills project, that it was more efficient to address the rates and facilities matters for the project in Proceeding 23799. The AUC approved placeholder treatment for the project costs until a determination was made in Proceeding 23799. The AUC also assigned a placeholder for one program, the Weld Assessment and Repair Program ("WARP"), due to Review Proceeding 24176. The AUC noted that any determination in the review proceeding may affect the consideration of the forecast WARP costs related to AP's 2019-2020 GRA.

Compliance with AUC Directions

The AUC was satisfied that the compliance application and subsequent information request ("IR") responses adequately addressed many of the directions, and set those out in Appendix 3 of its decision. It also set out directions that relate to future applications in Appendix 5 of its decision.

In its decision, the AUC focused on issues identified by interveners or the AUC, including AP's compliance with directions 1, 3, 4, 10, 12, 13, 27, 28, 30, and 35 from Decision 23793-D01-2019, and directions 1 and 4 from the IT Common Matters Decision.

Decision 23793-D01-2019

Direction 1 – 2019 Opening Rate Base

AP was directed to provide its 2018 rate base actuals in the compliance filing. The AUC was satisfied with the variance explanations provided by AP concerning its 2018 rate base and capital expenditures, including variances between forecast and actual. The AUC approved AP's 2018 closing rate base balance and the related 2019 opening rate base, subject to the AUC's determination regarding a further true-up of property, plant, and equipment ("PP&E") for 2018 and 2019 related to the IT Common Matters Decision.

AP was directed, in future compliance filings, to report actual expenditures by specific project and report all projects exceeding $500,000 that were not identified in the previous GRA and explain any deviations of over/under expenditures for large projects ($500,000+) against forecast expenditures.

Direction 3 - Weld Assessment and Repair Program

Given that WARP was under consideration in Proceeding 24176, the AUC directed AP to set the WARP placeholder amount at $0. AP complied with this direction. On January 10, 2020, the AUC issued Decision 24176-D01-202023 granting AP's variance of Decision 22986-D01-2018 and Decision 23537-D01-2018 (Errata). By granting AP's variance, the AUC approved AP's capitalized 2016 actual and forecast 2017-2018 reinspection and incremental repair costs (WARP costs) for inclusion in AP's 2017 opening rate base and 2017-2018 revenue requirement. AP was directed to revise its WARP placeholder to reflect the findings from Decision 24176-D01-2020 in the second compliance filing to this decision.

Direction 4 – Remote Operating Valve ("ROV") Program

AP was directed to provide additional information regarding the installation of ROVs. The AUC found that AP complied with Direction 4, by providing evidence of growing widespread industry consensus on their necessity and value; an explanation of advantages and disadvantages, as well as detailed cost estimates.

Direction 10 - Depreciation Expense

Direction 10 of Decision 23793-D01-2019 stated:

> 127. For these reasons, the Commission accepts ATCO Pipelines' proposal to credit depreciation expense in the amount of $1,584,000. ATCO Pipelines is directed to record the credit entry to depreciation expense as a one-time adjustment in the 2019 test year in its compliance filing to this decision. However, ATCO Pipelines is directed to record the debit side of the entry to the account of the shareholder because the shareholders were originally the beneficiaries of the PPA [prior period adjustment] in 2012 and that accounting was in error. ATCO Pipelines shall therefore not recover the debit side of the directed accounting entry through rate base or through revenue requirement.

In response to Direction 10, AP stated that it reflected the one-time adjustment to depreciation expense of $1,584,000, as directed. However, AP added that notwithstanding that Direction 10 sought to correct for the overcollection of depreciation expense collected from customers in revenue requirement from 2001 to 2012, it did not take into account the impact on return calculations during that same time frame in which accumulated depreciation was overstated.

> … while customers over contributed to depreciation in the amount of $1,584,000, that impact was partially offset by reduced rate base and correspondingly reduced regulated returns, until corrected by the 2012 prior period adjustment …

AP requested that the AUC consider the effect the error had on rate base and correspondingly, return on equity, and the appropriateness of symmetrically correcting for both these items. AP estimated the pre-tax return impact to be approximately $623,000, which reflected the returns resulting from the effect the error had on the lower rate base. The AUC agreed with this submission and found that AP had complied with Direction 10.

Directions 12 and 13 - Pressure Vessel Inspection Compliance Program

Direction 12 required AP to provide a revised timeline that included a risk assessment if the pressure vessel inspection compliance program was completed over a longer timeframe. AP was also required under Direction 13 to provide a status update on its pressure vessel inspection compliance program.

The AUC noted that with respect to Direction 12, although AP did not provide a revised timeline for the program to comply with the direction, it explained that implementing the program over a longer period would cause AP to be in non-compliance with CSA Z662 and API RP 510 for a greater period of time. The AUC accepted that AP's Pressure Vessel Inspection Compliance Program is necessary to bring AP into compliance with CSA Z662 and API RP 510, and that AP's timeline was reasonably supported. The AUC found that additional information provided by AP complied with Direction 13.

Direction 30 - Deferral Accounts

AP was directed to include any differences in the deferral balances arising from December 31, 2018, actual amounts in its compliance filing. The AUC found that in the application, AP did not provide any explanations of the adjustments made to deferral account balances and had not sufficiently complied with Direction 30. As no explanations were provided on the updated amounts in the deferrals, the AUC was not prepared to approve the requested one-time settlement of $3,896,000. The AUC directed AP, in its second compliance filing to this proceeding, to provide the explanations, and any supporting calculations, of the adjustments made to each deferral account balance identified.

Direction 35 – Head Office Rent

The AUC directed AP to file in its compliance filing, any information or evidence on how its corporate cost allocator for head office rent may be affected by the AUC's findings and determinations issued in the decision on Proceeding 22742 (where the AUC was considering head office rent and corporate allocations).

AP did not apply a proration formula to its compliance filing that was applied to ATCO Electric to reduce its head office costs. The AUC considered head office rent should be consistently calculated and that AP should provide information on the allocation of its costs employing a proration formula and using the best available information on total square footage, to ensure that no cross-subsidization of rent costs occurred or will occur between each of the ATCO Transmission Utilities, and between individual regulated and unregulated utilities in the ATCO Group of companies. The AUC directed AP to file, in its second compliance filing, a recalculation of its head office rent based on the AUC's findings and determinations issued in the decision arising from Proceeding 25282 (a variance application of 22742-D01-2019).

<u>Directions Related to IT Common Matters Costs</u>

This portion of the decision mirrored AUC Decision 24805-D01-2020, ATCO Electric Transmission, 2018-2019 General Tariff Application Compliance Filing, which is summarized in this newsletter. The only difference between this decision and Decision 24804-D01-2020 was an order for AP to provide a 2018 capital true-up associated with the IT common matters in AP's second compliance filing, with any 2019 IT capital true-up in its next GRA, consistent with the true-up of non-IT costs. In addition, for ATCO Electric, the AUC commented on ATCO Electric's tax deferral account.

***Blazer Water System Ltd. True-Up of 2019 Interim and Final Rates*, AUC Decision 25344-D01-2020**

Rates - Water - True-Up of Interim and Final Rates

In this decision the AUC considered an application from Blazer Water Systems Ltd. ("Blazer") concerning the true-up of interim and final rates for the period January 1, 2019, to October 31, 2019. The AUC approved Blazer's application. However, the AUC directed Blazer to recalculate the monthly true-up riders, and implement the true-up over an 18-month period instead of Blazer's proposed 12-month period.

Background

On November 22, 2018, the AUC issued Decision 22319-D01-2018, in which the AUC approved Blazer's existing rates as interim rates beginning January 1, 2019. On October 9, 2019, the AUC issued Decision 24418-D01-2019, approving Blazer's final rates for 2019 and 2020, and directing Blazer to file an application with the AUC concerning the true-up of interim and final rates for the period January 1, 2019, to October 31, 2019.

The total amount owing from Blazer to 103 Lynx Ridge Estates potable water customers, and three additional customers who were on the same interim rates as Lynx Ridge, was $11,152.93. The amount owed by 109 potable water customers in the Bearspaw Village and Blue Ridge Rise co-ops to Blazer was $16,850.30. The amount owed by the remaining 307 potable water customers to Blazer was $161,655.31.

With the exception of customers who moved from their service address, Blazer proposed to collect amounts owing from customers and refund amounts owed to customers over a 12-month period on a per service address basis by dividing the amount owing or owed for each customer by 12.

AUC Findings

Irrigation Refund

Given that Blazer filed the true-up amount owing to the Lynx Ridge condominiums in this proceeding, and confirmed that this amount was refunded, the AUC found that Blazer complied with its true-up requirements as it concerned the Lynx Ridge condominiums.

Individual True-Up Riders

Given Blazer's relatively small customer base, the fact that Blazer had already done the necessary work to calculate individual true-up riders, and the disparity in consumption amounts and subsequent amounts owing for refund or collection, the AUC agreed that individual true-up riders were just and reasonable. While this meant that some customers would face significantly larger collections than others, the AUC acknowledged that these collection amounts were directly tied to the volume of customers' water consumption. It would be unreasonable in this circumstance to ask customers who consume lower volumes to pay more than their calculated share of the true-up amounts, effectively cross-subsidizing higher consumption customers. For these reasons, the AUC approved Blazer's proposal to apply the true-up riders on an individual, customer by customer basis.

Rate Shock and Term of True-Up Collection

Blazer also acknowledged that the proposed individual rate riders would result in an increase to the average monthly interim rates greater than 10 percent. However, Blazer noted that the individual rate riders would represent an average monthly rider of $13 for Bearspaw Village and Blue Ridge Rise customers, and $35 for other potable water customers and submitted that these amounts would not represent an undue hardship for Blazer's customers. Blazer added that it operated on interim rates since at least January 2019 and that to prolong true-up collection would mean Blazer would not be paid its approved rates in full for a period exceeding three to four years.

The AUC noted that it typically considers any rate increase greater than 10 percent to constitute rate shock. Although no customers objected to Blazer's application or even filed statements of intent to participate on the record of this proceeding, the AUC indicated it must still consider the rate shock implications of Blazer's proposed true-up period. The AUC acknowledged that Blazer operated, and continues to operate, under a revenue shortfall. However, the AUC also noted that Blazer was already granted a significant rate increase in 2019, which itself could have been considered to constitute rate shock. Further, the rates approved in Decision 24418-D01-2019 were for a test period ending on December 31, 2020. The AUC stated that Blazer may request new rates at that time. For these reasons, and in light of the current economic climate in Alberta due to the COVID-19 pandemic, the AUC indicated it is not prepared to approve another rate increase of the magnitude proposed by Blazer.

Accordingly, the AUC directed Blazer to recalculate the monthly true-up riders, and implement the true-up over an 18-month period.

***Capital Power Generation Services Inc. Cancellation of Genesee Generating Station Units 4 and 5*, AUC Decision 25656-D01-2020**
Facilities - Cancellation of Generating Station Units

In this decision, the AUC responded to a request from Capital Power Generation Services Inc. ("Capital Power") to rescind Approval 23963-D02-2018 to construct and operate units 4 and 5 of the Genesee Generating Station. The AUC found that rescission of the approval was in the public interest.

Background

Pursuant to Approval 23963-D02-2018 Capital Power had approval to construct and operate units 4 and 5 of a power plant designated as the Genesee Generating Station, located approximately 30 kilometres southwest of Stony Plain (the "Project").

Pursuant to section 22 of the *Hydro and Electric Energy Act*, Capital Power provided formal notification to the AUC that it would not be proceeding with the Project and requested that the Project's power plant approval and associated directions be rescinded.

AUC Findings

The AUC acknowledged that Capital Power confirmed no adverse environmental impact would be caused by the proposed cancellation of the Project and that stakeholders would be notified in accordance with the requirements of Rule 007.

Based on the information provided, the AUC found that rescission of the approval was in the public interest. Pursuant to section 8 of the *Alberta Utilities Commission Act*, the AUC rescinded Capital Power's Approval 23963-D02-2018, to construct and operate units 4 and 5 of the Genesee Generating Station.

***Direct Energy Regulated Services Application for Final Review and Disposition of Regulated Rate Option Rate Cap Deferral Account,* AUC Decision 25630-D01-2020**
Rates - Regulated Rate Option Rate Cap Deferral Account

In this decision, the AUC considered an application from Direct Energy Regulated Services ("DERS") pursuant to *An Act to Cap Regulated Electricity Rates* ("*Act*") and one of its associated regulations, and the *Rate Cap (Commission Approved Regulated Rate Tariffs) Regulation* ("*Regulation*"). Section 6(1) of the *Regulation* requires DERS to apply to the AUC for a final review and disposition of its regulated rate option ("RRO") rate cap deferral account. In the application, DERS requested a final review and disposition of its rate cap deferral account. The AUC approved the disposition of DERS' RRO rate cap deferral account.

Background

During the period beginning on June 1, 2017, and ending on November 30, 2019, the *Act* imposed maximum rates for the monthly electric energy charges that DERS, as an RRO provider, could bill its RRO customers. The monthly electric energy charges during this period were determined as the lower of: (i) 6.8 cents per kilowatt-hour (kWh); or (ii) the applicable monthly amount determined in accordance with DERS' energy price-setting plan ("EPSP"). For the months during this period where the applicable monthly electric energy charge for a rate class determined in accordance with DERS' EPSP exceeded 6.8 cents/kWh, the Government of Alberta would make payments to DERS for the difference.

To administer the payments from the Government of Alberta, DERS was required under the *Regulation* to establish a deferral account. DERS was required to include deferral account statements as part of the monthly electric energy charges filings it made to the AUC, even if there was no payment being requested for the month.

The Role of the AUC

The AUC has oversight regarding two aspects of the RRO rate cap program. The first aspect of the program the AUC has oversight over is the filing of the deferral account statements by DERS and the other RRO providers each month. The second aspect is the filing of applications for the AUC's final review and disposition of the RRO providers' rate cap deferral accounts for the period that the rate cap was in effect. This decision addressed the second aspect of the RRO rate cap program.

Section 6 of the *Regulation* sets out the requirements regarding the final review and disposition of DERS' RRO rate cap deferral account. Section 6(1) of the *Regulation* required DERS to apply to the AUC for the final review and disposition within six months after November 30, 2019.

Details of the Application and AUC Review

DERS provided a schedule in Appendix 1 of its application that included information for each of the months from June 2017 to November 2019 for each of its customer rate classes. Appendix 1 showed: (i) the actual consumption volume in kWh; (ii) the RRO rates determined in accordance with its approved EPSP; (iii) the maximum rate of 6.8 cents/kWh; and (iv) the final calculated deferral amounts for any months where the RRO rates determined in accordance with its approved EPSP exceeded the maximum rate of 6.8 cents/kWh. The final calculated deferral amounts reported excluded the GST.

The schedule in Appendix 1 of the application also included corrected monthly RRO rates for February 2018 to September 2019, determined in accordance with DERS' approved EPSP. These corrected rates were approved in Decision 24412-D01-2019 and resulted in DERS having to correct certain previously filed and approved deferral account statements.

The schedule in Appendix 1 of DERS' application set out final calculated deferral amounts for the applicable months of April 2018, July through December 2018, January and February 2019, and July through November 2019.

The AUC reviewed the monthly approved deferral account statements for all the months listed above, and it confirmed that DERS only included non-zero deferral amounts for the months listed in the previous paragraph, with the exception of December 2019. DERS did not receive any deferral amount payment from the Government of Alberta for December 2019.

Using information from the applicable AUC-approved monthly deferral account statements for DERS, the AUC confirmed that the final deferral amounts as calculated by DERS for each month agreed to the total payment amounts for these months.

The AUC identified differences between the final deferral amount and the total payments for July 2018, August 2018, September 2018, October 2018, December 2018, January 2019, February 2019, and November 2019, but found that the differences were immaterial, and would not result in any material misstatements of the deferral amounts that were reported by DERS.

AUC Decision

Based on its review, the AUC approved the disposition of DERS' RRO rate cap deferral account. The AUC confirmed that no amount remained owing to DERS and that DERS has not been overpaid any amount.

***ENMAX Energy Corporation 2017-2020 Regulated Rate Option Non-Energy Tariff Compliance Application*, AUC Decision 25551-D01-2020**

Rates - Compliance Filing - Regulated Rate Option Non-Energy Tariff

In this decision, the AUC considered a 2017-2020 regulated rate option ("RRO") non-energy tariff compliance application to Decision 23752-D01-2020 from ENMAX Energy Corporation ("EEC"). The AUC found that EEC complied with the AUC's directions in Decision 23752-D01-2020, with the exception of Direction 2 - 2017-2019 Interim-to-final rate true-up, which would be assessed in a future proceeding.

Background

In its 2017-2020 RRO non-energy tariff application, EEC had requested the following:

(a) approval of EEC's 2017-2020 RRO Non-Energy rates ("Administration Charges") for residential and commercial customers;

(b) a streamlined compliance process, as described in Bulletin 2016-18; and

(c) approval to implement the 2020 Administration Charges beginning the first calendar month at least ten days after AUC approval.

AUC Directions

Direction 1 – Summary and Submission of Compliance Filing by May 1, 2020

EEC filed its compliance application on May 12, 2020. The AUC found that EEC complied with this direction as modified by a deadline extension.

Direction 2 – 2017-2019 Interim-to-Final Rate True-Up

The AUC issued a direction for EEC to file reconciliation information for the true-up of 2015-2016 rates in conjunction with any rider application that may be required to true-up 2017-2019 rates.

The AUC accepted an EEC proposal to apply to true-up its 2017-2020 rates once it receives final approval of its administration charges. Accordingly, the AUC indicated it would determine EEC's compliance with this direction in a future proceeding.

Direction 3 – Inflation

The AUC directed EEC to use the Alberta CPI [consumer price index] estimate as its non-labour inflation factor from the Fall 2019 Calgary and Region Economic Outlook, to a maximum of 2.0 per cent, as the inflation factor in determining its forecast revenue requirement for 2020.

The AUC confirmed that EEC used the appropriate labour and non-labour escalation rates of no more than 2.0 percent as the inflation factor in determining its forecast revenue requirement for 2020, as directed in Decision 23752-D01-2020 and therefore that EEC complied with this direction.

Direction 4 – Monthly Site Count Data

The AUC directed EEC as part of the compliance filing, to update the RRO monthly site count data for 2019 and 2020 by using actual data for all months where such data is available, and to incorporate this actual data in deriving the forecast for the remaining months.

EEC stated that it used actual site count data up to and including March 2020 to update the remaining monthly forecast site data for 2020. Annual site count data is shown in the table below:

Table 1. EEC actual and forecast annual site count data

	2017 Actual	2018 Actual	2019 Actual	2020 Forecast
Residential	165,381	161,044	152,690	144,736
Commercial	12,563	12,437	11,940	11,468
Total	**177,944**	**173,481**	**164,629**	**156,204**

The AUC indicated it understood that EEC ran its forecasting model, based on available actual data, as directed in Decision 23752-D01-2020. While the 2020 forecast site count was lower than previous forecasts, the AUC attributed this to EEC's use of actual data. Based on the update to its site count forecast, the AUC found that EEC complied with this direction.

Direction 5 – Bad Debt

The AUC directed EEC in the compliance filing, to continue to use its current methodology for calculating bad debt, and to revise its bad debt forecast accordingly.

The AUC indicated it understood that EEC's methodology for forecasting bad debt has not changed, but rather EEC made a change to the impairment methodology for accounts receivable. The AUC noted that EEC decreased its 2018 bad debt amount by $662,000, reversing the one-time increase that was applied in its original application due to International Financial Reporting Standard 9. In its original application, EEC inflated its 2019 bad debt forecast by two percent to arrive at the 2020 forecast amount. EEC continued to use this methodology in this compliance application. However, it reduced the inflation rate to 1.9 percent, which corresponded with the Alberta CPI used by EEC in this compliance application. Given the reduction to the bad debt amount in 2018, the AUC found that EEC complied with this direction.

Direction 6 – Billing and Customer Care Cost Allocation Methodology

The AUC directed EEC to use its current billing and customer care ("B&CC") cost allocation methodology and file the resulting cost allocations and corresponding rates in the compliance filing.

The AUC found that EEC had used its current allocation methodology to allocate the B&CC costs. On that basis, the AUC considered that EEC complied with this direction.

Direction 7 – Motion for Confidential Treatment

The AUC issued the following direction:

> As noted in the Commission's findings and directions in this decision, a compliance filing for EEC's 2017-2020 RRO Non-Energy Tariff application is required. In order for EEC to utilize the new functionality of the AUC eFiling System for the exchange of confidential documents in EEC's compliance filing, pursuant to Bulletin 2020-05: Amendments to AUC Rule 001 to facilitate exchange of confidential documents, the Commission must grant confidentiality treatment to the information related to the compliance filing that cannot be filed on the public record. To this end, the Commission directs EEC in its compliance filing to submit a motion for confidential treatment of information.

EEC filed a letter with the AUC on April 21, 2020, requesting that the AUC extend the confidentiality treatment originally granted in Proceeding 23752 to this compliance filing proceeding. In response to EEC's letter, the AUC issued a ruling in Proceeding 25523, on April 24, 2020. In the ruling, the AUC extended the confidential treatment to certain documents in EEC's 2017-2020 RRO non-energy application to this compliance filing. On this basis, the AUC considered that EEC had complied with this direction.

Direction 8 – Listing of Confidential Documents

The AUC issued the following direction:

> In addition, the Commission considers it would be efficient if all EEC confidential documents filed on the record of this proceeding were migrated to the compliance filing. In its motion under Section 28 of Rule 001, the Commission directs EEC to provide a list of its confidential documents filed in this proceeding (with the previous public document or the public placeholder for the confidential document clearly identified in the format of Exhibit 23752-X0000). In addition, the list must identify any new documentation that will require confidential treatment in the proceeding for the compliance filing.

The AUC noted that EEC provided a list of the confidential documents filed in Proceeding 23752. In addition, EEC filed Exhibit 25551-X0007-Confidential, which contained the confidential documents filed in Proceeding 23752. The AUC found that EEC complied with this direction.

Requested Approvals

EEC requested approval of the following proposed administration charges:

Table 4. 2017-2020 proposed administration charges

Type of Customer	2017 Actual	2018 Actual	2019 Forecast	2020 Forecast
	($/site/day)			
Residential	0.2000	0.2041	0.2115	0.2201
Commercial	0.1820	0.1798	0.1888	0.1975

EEC indicated that the proposed administration charges were calculated based on the RRO site count in Table 1 of this decision and the following forecast revenue requirement:

Table 5. Forecast revenue requirement

	2017 Actual	2018 Actual	2019 Forecast	2020 Forecast
	($000)			
Revenue Requirement	$12,908	$12,813	$12,609	$12,486

The AUC found that EEC complied with the AUC directions from Decision 23752-D01-2020, with the exception of Direction 2 - 2017-2019 Interim-to-final rate true-up, which would be assessed in a future proceeding. The AUC indicated it had also reviewed the forecast revenue requirement and RRO site count. The AUC was satisfied that the 2017-2020 proposed administration charges were calculated using the forecast revenue requirement and RRO site count, and found that the proposed administration charges would result in just and reasonable rates. On this basis, the AUC approved EEC's 2017-2020 administration charges, as shown in Table 4.

The AUC directed EEC to implement its 2020 administration charges beginning the first calendar month at least 10 days after AUC approval of these rates. Based on the issue date of this decision, the AUC noted that these rates would be effective August 1, 2020.

***ENMAX Energy Corporation 2019-2022 Energy Price-Setting Plan Compliance Filing*, AUC Decision 25537-D01-2020**

Rates - Energy Price-Setting Plan

In this decision, the AUC considered a compliance filing from ENMAX Energy Corporation ("EEC") for its 2019-2022 regulated rate option ("RRO") energy price-setting plan ("EPSP"). The EPSP utilizes a competitive auction methodology for procuring energy and for establishing the energy charge to be paid by its RRO customers. The AUC approved the 2019-2022 EPSP but required EEC to file revisions to its EPSP, with all schedules and appendixes to the EPSP.

Background

On July 15, 2019, EEC filed an application with the AUC requesting approval of its 2019-2022 EPSP. On March 19, 2020, the AUC issued Decision 24721-D01-2020, which determined that the proposed auction design satisfied the requirements set out in the Regulated Rate Option Regulation, but it found that certain components of EEC's 2019-2022 EPSP would require a compliance filing. Eleven directions were issued in the decision, with nine directions relating to EEC's compliance filing. Direction 8 solely related to future EPSP applications and was not included in the AUC's findings in this decision.

<u>Non-Routine and New Issues</u>

Non-routine elements in EEC's 2019-2022 EPSP compliance filing included a URICA Energy Management Corp.'s ("URICA") proposal for auction monitoring that would be undertaken for EEC, ICE NGX Canada Inc. ("NGX") auction software and platform development costs, and NGX auction hosting service fees.

Auction Monitoring (Direction 2)

The AUC directed EEC to submit a proposal for an auction monitoring report and process. EEC retained URICA Energy Management Corp. ("URICA") to prepare a proposal, which EEC included as Appendix 6 to its application. EEC added that this direction appeared to align with an information request ("IR") from the Utilities Consumer Advocate ("UCA") and that URICA's proposal was accordingly guided by the information requested in that IR. EEC advised that the cost of URICA providing this service is $3,750 per month, which EEC proposed to recover through its energy charges.

Given the expected costs for the auction monitoring process proposed by EEC through the use of URICA, the AUC found that the services went beyond what is reasonably necessary to provide auction monitoring that would be beneficial to the AUC and ratepayers. This was particularly apparent for certain URICA services, such as URICA's participant commentary on a current auction or commentary on notable news items prior to or on the day of the auction. The AUC considered the UCA's list of items for auction monitoring, with the exception of item (iii) (the number of bidders with a financial position and the number of bidders with a physical position) to be reasonable, but noted that EEC's proposal for analyses and expertise that would be provided by URICA went beyond this list.

Upon further consideration, the AUC concluded that it is not necessary for EEC to report its auction statistics each month. The AUC considered that it is sufficient for EEC to report on auction statistics only for delivery months where there are concerns with the competitiveness of any auctions, including but not limited to, any auctions that fail the competitiveness assessments. Any reports to the AUC must be filed in conjunction with that delivery month's energy charge filing and must include the following: the number of confirmed suppliers and bidders; competitive assessment results; the results of the specific auctions being reported; and whether there were any cancelled or contingency auctions for the delivery month. The information is intended to inform the AUC on the status of the operation of the auctions and energy procurement under the 2019-2022 EPSP and is not intended to disturb any reporting that may be required by the Market Surveillance Administrator under its mandate and duties specified in the *Alberta Utilities Commission Act*.

Auction Development and Hosting (AUC Direction 3)

The AUC directed EEC to provide an estimate of the auction development and deployment costs and lead time in a compliance filing. In response to the AUC's direction, EEC negotiated a one-time charge of $500,000 with NGX for developing the auction software to be recovered over 12 months. This one-time development charge did not include the cost of any future modifications to the auction software. The specific terms of this charge were included in the Professional Services Agreement ("PSA") filed on the confidential record.

In an IR to EEC, the AUC referred to an EPCOR Energy Alberta GP Inc. ("EPCOR") post-disposition document filed on July 20, 2018, in connection with Proceeding 22357 regarding EPCOR's 2018-2021 EPSP, where EPCOR indicated that NGX's cost to develop the software for the descending clock auctions was capped at a maximum of $250,000.

The AUC stated that the $500,000 is significantly different than a similar auction development cost charged to EPCOR and stated that EEC could have submitted, on the record, a budgetary quote from NGX at the time EEC proposed a move to the descending clock auction in the original proceeding. The AUC considered that the budgetary quote on the descending clock auction development costs should have been available for review to the AUC and interveners early in the process for more full and proper consideration. Accordingly, the AUC directed EEC in all future EPSP applications for contracts for third-party service for an itemized budgetary quote for services and any other corollary services to be included with its original EPSP applications rather than waiting to provide this information in the compliance filing. The cost put forward by EEC in this compliance filing represents a material deviation from the historical costs that NGX has charged for auction development costs. The AUC noted the lack of support, itemization, or derivation of costs for the $500,000 quote, and was not satisfied with the reasons provided by EEC and NGX for the quantum of costs. For these reasons, the AUC denied EEC's request for $500,000 in auction development costs to be recovered through the EPSP. Instead, the AUC, in its discretion, granted $250,000 to EEC, to be recovered over 12 months.

Concerning a $150,000 annual hosting fee, the AUC found merit in NGX's explanation to provide continuous technical support and cybersecurity enhancements in order to host the descending clock auctions, and the AUC accepted that there will be reasonable costs each year to maintain cybersecurity. Further, an itemized description was provided which provides transparency. Accordingly, the AUC granted the $150,000 annual hosting fee for the term of EEC's 2019-2022 EPSP, to be collected monthly on a pro-rata basis.

<u>Routine Issues</u>

Backstop Report (Direction 5)

The AUC directed EEC to update its EPSP to indicate that a backstop report will be provided to the AUC for any month in which the backstop mechanism is triggered. EEC complied with this direction.

Errors and Omissions (AUC Direction 9)

The AUC directed EEC to include in the compliance filing a consolidated list of all errors and omissions in the EPSP from Proceeding 24721 that were corrected in the compliance filing. EEC complied with this direction. EEC was required to make additional corrections as part of its revised EPSP in a post-disposition filing.

Directions 1, 4, 6, 7, 10 and 11

In paragraph 145 of Decision 24721-D01-2020, the AUC made the following direction:

> 145. In the scenario where EEC needs to procure an additional peak product block for a delivery month, the Commission directs EEC to exclude the procurement cost of the additional block in the base energy charge and clearly convey this in its monthly filings. The Commission views that this additional peak block should not be used in the calculation of the monthly energy charge because the monthly energy charge should be based on the price of the full-load product. The Commission also views that the additional peak product block will be treated the same as the other peak blocks and will be used to calculate the CRC [commodity risk compensation]: the procurement of the flexible peak hedging block should not affect the application of the CRC to 60 per cent of EEC's RRO load obligation, but rather netted against the CRC gains and losses for EEC.

EEC stated that it edited Schedule F of the EPSP and the auction tab of its illustrative energy charge model to reflect this direction, which is Direction 1. The AUC found that EEC complied with this direction but also noted that this direction is an ongoing direction that applies for the term of the EPSP.

In Direction 4, the AUC directed EEC to disclose the base energy charge and CRC components separately in its energy charge model. The AUC found that EEC complied with this direction.

In Direction 6, the AUC directed EEC to amend its EPSP such that the backstop request for quotation ("RFQ") is sent to all confirmed backstop suppliers. The AUC found that EEC complied with this direction.

In Direction 7, the AUC directed EEC to include in Schedule 2 of its Rule 005 filings the applicable pre-tax reasonable return rates in dollars per megawatt-hour. For this application, the AUC reviewed EEC's 2019 Rule 005 filing and confirmed that EEC included its pre-tax reasonable return in dollars per megawatt-hour. EEC therefore complied with this direction, but the AUC noted that this direction is ongoing.

In Direction 10, the AUC directed EEC to submit a motion for confidential treatment of information in accordance with Bulletin 2020-05. In Direction 11, the AUC stated that it would be efficient if all of EEC's confidential documents from Proceeding 24721 were migrated to the compliance filing record and directed EEC to provide a list of confidential documents filed in Proceeding 24721. The AUC found that EEC complied with these two directions.

Approval and Implementation of EPSP

The AUC considered the directions to EEC that require it to file a revised EPSP, with all schedules and appendixes to the EPSP as a post-disposition document on this proceeding, will not affect the essential functioning of the EPSP and implementation of the auction. Rather, certain components of EEC's 2019-2022 EPSP require revision to conform with the AUC's findings and the associated disallowance of certain EPSP costs, as directed in this decision. Consequently, the AUC noted that nothing precludes EEC from immediately commencing work with NGX to implement the auction and the AUC approved EEC to start implementing the auctions.

***ENMAX Energy Corporation Application for Final Review and Disposition of Regulated Rate Option Rate Cap Deferral Account*, AUC Decision 25625-D01-2020**

Rates - Regulated Rate Option Rate Cap Deferral Account

In this decision, the AUC considered an application from ENMAX Energy Corporation ("EEC"), pursuant to *An Act to Cap Regulated Electricity Rates* ("*Act*") and one of its associated regulations, the *Rate Cap (Commission Approved Regulated Rate Tariffs) Regulation* ("*Regulation*"). Section 6(1) of the *Regulation* requires EEC to apply to the AUC for a final review and disposition of its regulated rate option ("RRO") rate cap deferral account. The AUC determined that EEC had been overpaid and that the overpayment had to be repaid by EEC to the Government of Alberta within 30 days after this decision was issued.

Background

During the period beginning on June 1, 2017, and ending on November 30, 2019, the *Act* imposed maximum rates for the monthly electric energy charges that EEC, as an RRO provider, could bill its RRO customers. The monthly electric energy charges during this period were determined as the lower of: (i) 6.8 cents per kilowatt-hour ("kWh"); or (ii) the applicable monthly amount determined in accordance with EEC's energy price-setting plan ("EPSP"). For the months during this period where the applicable monthly electric energy charge for a rate class determined in accordance with EEC's EPSP exceeded 6.8 cents/kWh, the Government of Alberta would make payments to EEC for the difference.

For any months where payments were to be made to EEC by the Government of Alberta, the initial payment amount was determined using the electric energy charge difference (i.e., the difference between the charge determined in accordance with the EPSP and 6.8 cents/kWh) by rate class applied to the forecast consumption in kWh for the rate class. Once the actual consumption in kWh for the rate class was determined through the final load settlement calculations, the deferral amount difference caused by the mismatch between the forecast consumption and the actual consumption was accounted for, and the resulting payment amount was either refunded to the Government of Alberta by EEC or paid to EEC. Section 3(3)(b)(ii) of the *Regulation* allows for an adjustment in a given month to account for the actual consumption in kWh of customers in each rate class determined through the final load settlement calculations.

To administer the payments from the Government of Alberta, EEC was required under the *Regulation* to establish a deferral account. EEC was required to include deferral account statements as part of the monthly electric energy charges filings it made to the AUC, even if there was no payment being requested for the month.

The Role of the AUC

The AUC explained that it has oversight regarding two aspects of the RRO rate cap program. The first aspect of the program related to the filing of the deferral account statements by EEC and the other RRO providers each month. The second aspect was the filing of applications for the AUC's final review and disposition of the RRO providers' rate cap deferral accounts for the period that the rate cap was in effect. This decision addressed the second aspect of the RRO rate cap program.

Sections 6(2) to 6(5) of the *Regulation* specify the role of the AUC regarding an application for a final review and disposition of an RRO rate cap deferral account:

> (2) In conducting a final review and disposition of an owner's deferral account the Commission shall review the deferral account statements submitted by the owner in respect of the period beginning on June 1, 2017, and ending on November 30, 2019, to confirm the information and amounts set out in the deferral account statements and determine whether
>
> > (a) an amount remains owing to the owner under section 2(1) of this Regulation, or
> >
> > (b) the owner has been overpaid an amount under section 2(1) of this Regulation.
>
> (3) An owner shall provide to the Commission any records or other information the Commission may require to confirm the information and amounts set out in deferral account statements submitted by the owner.
>
> (4) If, on a final review, the Commission determines that an amount is owing to an owner under section 2(1), the amount shall be paid to the owner within 30 days after the date of the Commission's determination.
>
> (5) If, on a final review, the Commission determines that an owner has been overpaid under section 2(1), the owner shall repay the amount to the Minister within 30 days after the date of the Commission's determination.

Details of the Application and AUC Review

EEC provided a schedule in Appendix 2 of its application that included the following information for each of the months from June 2017 to November 2019 for its residential and commercial customer rate classes: (i) the actual consumption volume in kWh; (ii) the RRO rates determined in accordance with its approved EPSP; (iii) the maximum rate of 6.8 cents/kWh; and (iv) the final calculated deferral amounts for any months where the RRO rates determined in accordance with its approved EPSP exceeded the maximum rate of 6.8 cents/kWh. The final calculated deferral amounts reported excluded the GST.

Table 3 included the results of the AUC's confirmation of payment amounts, and set out the initial payments and the true-up payments relating to the difference between the initial and final volumes:

Table 3. Payment amounts regarding final deferral account amounts[18]

Month and year	Final deferral amount as calculated by EEC	Initial payment	Initial payment proceeding	True-up payment between initial and final volume	True-up payment proceeding	Total payments[19]
	$	$		$		$
April 2018	2,654,398.12327	2,490,621.10145	23442	163,777.02183	23929	2,654,398.12327
July 2018	1,755,191.51440	1,779,046.67062	23689	(23,855.15622)	24160	1,755,191.51440
August 2018	2,794,444.68441	2,885,870.91548	23777	(91,426.23107)	24274	2,794,444.68441
September 2018	1,503,783.92567	1,541,363.99013	23853	(37,580.06446)	24347	1,503,783.92567
December 2018	679,553.32391	726,779.24552	24095	(47,225.92162)	24600	679,553.32391
January 2019	1,079,932.59819	1,123,219.31423	24160	(43,286.71604)	24668	1,079,932.59819
February 2019	248,382.45426	218,493.72918	24274	29,888.72508	24769	248,382.45426
July 2019	1,559,701.85716	1,641,044.96425	24668	(81,343.10709)	25207	1,559,701.85716
August 2019	1,887,901.17097	1,976,945.30831	24769	(89,044.13734)	25315	1,887,901.17097
September 2019	707,631.89931	733,701.68950	24833	(26,069.79020)	25393	707,631.89931
November 2019	625,448.42450	642,895.66102	25021	(17,447.23652)	25531	625,448.42450
Total	15,496,369.97605	15,759,982.58970		(263,612.61364)		15,496,369.97605

The AUC determined the final deferral amounts for EEC as shown in Table 5 below:

Table 5. Commission-determined final deferral amounts for EEC, excluding GST

Month and year	Final deferral amounts as determined by the AUC
	$
April 2018	2,654,398.12327
July 2018	1,709,948.06028
August 2018	2,794,444.68441
September 2018	1,503,783.92567
December 2018	679,553.32391
January 2019	1,079,932.59819
February 2019	248,382.45426
July 2019	1,559,701.85716
August 2019	1,887,901.17097
September 2019	707,631.89931
November 2019	625,448.42450
Total	15,451,126.52193

The AUC compared the total AUC-determined final deferral amount for EEC in Table 5 of $15,451,126.52, excluding GST, to the total payment amount of $15,496,369.98, excluding GST. The AUC determined in accordance with section 6(2) of the *Regulation* that EEC had been overpaid an amount, pursuant to sections 2(1) and 6(2) of the *Regulation*. The overpayment was $45,243.45, plus GST, with a resulting total of $47,505.63. Section 6(5) of the *Regulation* stipulates that this overpayment must be repaid by EEC to the Government of Alberta within 30 days after issuance of this decision.

***EPCOR Distribution & Transmission Inc. Compliance Filing to Decision 24798-D01-2020 2020-2022 Transmission Facility Owner General Tariff Application*, AUC Decision 25664-D01-2020**

Rates - Compliance Filing

In this decision, the AUC considered an application filed by EPCOR Distribution & Transmission Inc. ("EDTI") requesting approval of its compliance filing to Decision 24798-D01-2020, EDTI's 2020-2022 transmission facility owner ("TFO") general tariff application ("GTA"). The AUC approved EDTI's application.

Compliance with the AUC's Directions from Decision 24798-D01-2020

In compliance with the directions in Decision 24798-D01-2020, EDTI revised its 2020-2022 forecast revenue requirement to the following amounts:

Table 1. 2020-2022 revised forecast revenue requirement

Description	2020	2021	2022
Proceeding 24798	$109.88 million	$113.50 million	$116.27 million
Proceeding 25664	$108.44 million	$110.63 million	$113.11 million
Variance – Increase (decrease) in revenue requirement	$(1.44) million	$(2.87) million	$(3.16) million

Source: Exhibit 24798-X0067, Schedule 3-1 and Exhibit 25664-X0026, Schedule 3-1.

The AUC was satisfied that EDTI's compliance filing adequately addressed and responded to directions 1, 2, 3, 5, 6, 7, 10, 11, 12, 15, 16 and the determination found in paragraph 61 from Decision 24798-D01-2020, which were set out in Appendix 2 to this decision. As listed in Appendix 3 to the decision, the remaining outstanding directions 4, 8, 9, 13, and 14 and the determination found in paragraph 260 were intended for the next or all future GTAs.

The AUC considered EDTI's responses to directions 2 and 10 in more detail as follows.

Direction 2 of Decision 24798-D01-2020

Direction 2 of Decision 24798-D01-2020 stated:

> The Commission has reviewed EDTI's required adjustments and supporting explanations as outlined in its IR responses and finds them to be reasonable. For this reason, the Commission accepts EDTI's proposal to record any damper-related costs on a placeholder basis subject to the outcome of any future litigation related to the dampers. For clarity, the Commission is not making a finding as to the prudency of these costs at this time and further notes that these costs are likely to remain as placeholders until the conclusion of Proceeding 24681, or [upon] the completion of any future litigation. The Commission also accepts EDTI's proposal to correct the $0.93 million AFUDC [allowance for funds used during construction]-related error in its compliance filing to this decision. EDTI is directed to record the required entry in its compliance filing to this decision.

The AUC was satisfied that EDTI complied with Direction 2 by correcting the AFUDC-related error through a $0.93 million addition to rate base in 2019. Further, the AUC found that EDTI adequately supported its adjustments of $6.50 million and negative $1.93 million in capital additions related to land in 2017 and 2018 and approved these capital addition costs in rate base.

Direction 10 of Decision 24798-D01-2020

Direction 10 of Decision 24798-D01-2020 stated:

> In the current proceeding, the Commission has reviewed the Stage 5 CCD [customer contribution decision] #1, as was provided in response to EDTI-AUC-2019SEP25-038(b). As discussed above, the Stage 5 CCD #1 was issued on June 14, 2016, when EDTI expected the AESO [Alberta Electric System Operator] to issue an updated CCD in late 2019. If updated, EDTI would have advised the Commission of any changes to its TFO local investment amount in this proceeding. As of the close of record, no updates have been provided to the Commission. Given that no updates have been provided by EDTI and in light of the delay in proposed in-service dates, the Commission will not approve a rate base addition for the Genesee G4/G5 Switchyard Expansion Project during the test years. EDTI is directed to remove its forecast capital addition for the Genesee G4/G5 Switchyard Expansion Project in its compliance filing to this decision.

The AUC acknowledged the cancellation of the Genesee G4/G5 Switchyard Expansion Project and EDTI's removal of the Project from its forecast revenue requirement.

Discussion of True-Up Mechanism for EDTI's 2020 Transmission Tariff

The AUC noted that EDTI is currently providing transmission service to the AESO under its 2020 interim tariff approved by the AUC in Decision 24931-D01-2019. In that decision, the AUC approved an interim monthly tariff of $8,554,316 per month, effective January 1, 2020. The AUC explained that this 2020 interim tariff would continue to apply until the AUC approved a final 2020 transmission tariff.

EDTI calculated the required January 2020 through July 2020 true-up amount and the new monthly tariff effective August 2020, as shown in the table below:

Table 2. Proposed 2020 true-up calculation

	2020	Calculated as
2020 final revenue requirement	$108,440,000	
2020 final monthly charge to the AESO	$9,036,667	$108,440,000 / 12 months
2020 revenue to be collected under final rates from January 1 – July 31, 2020	$63,256,667	$9,036,667 x 7 months
2020 interim tariff collected from January 1 – July 31, 2020	$59,880,212	$8,554,316 x 7 months
2020 true-up amount to be collected from the AESO	**$3,376,455**	

Source: Exhibit 25664-X0031, EDTI-AUC-2020JUN23-002(a).

EDTI provided its proposed monthly tariff to be charged to the AESO for the use of EDTI's transmission facilities for 2020-2022 based on EDTI's revenue requirement shown in Table 1 above.

The AUC found that the annual tariff and monthly rates for the 2020-2022 test years corresponded to the respective revenue requirements and approved them on a final basis. The AUC also approved a one-time charge of $3,376,455 to be collected from the AESO for the revenue shortfall resulting from the difference between EDTI's interim and approved monthly tariffs between January 1, 2020, and July 31, 2020.

Regarding the timing of EDTI's decision to dispose of the South Training Centre ("STC") property, EDTI had vacated the building in 2017 and transferred the functions served by the STC property to other properties owned by EDTI. However, EDTI stated that EDTI management had not determined until earlier this year that the STC property will not continue to be needed by EDTI for utility service in the future.

EPCOR Distribution & Transmission Inc., Disposition of the South Training Centre, **AUC Decision 25443-D01-2020**

Facilities - Disposition Application

In this decision, the AUC considered an application from EPCOR Distribution & Transmission Inc. ("EDTI") for the disposition of its South Training Centre ("STC"). The AUC approved EDTI's application to dispose of the STC property and found that the transaction was outside the ordinary course of business.

Background

In the application, EDTI requested approval to dispose of the STC property, which includes the land, a building, a fenced yard, and a parking lot (the "STC property"). The STC property was used by EDTI as an employee office space, indoor classroom space, and an outdoor, field-based training facility.

Neither training facility space nor materials storage at the STC property is currently required by EDTI, and EDTI explained the STC property is no longer required for the provision of electric utility service.

Legislation

As a designated owner of a public utility pursuant to section 101(1) of the *Public Utilities Act* and its designation regulation, EDTI is subject to section 101(2) of the *Public Utilities Act*, which states:

> 101(1) The Lieutenant Governor in Council may by regulation designate those owners of public utilities to which this section and section 102 apply.
>
> (2) No owner of a public utility designated under subsection (1) shall …
>
> (d) without the approval of the Commission,
>
> (i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of them, or
>
> (ii) merge or consolidate its property, franchises, privileges or rights, or any part of them,
>
> and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a public utility designated under subsection (1) in the ordinary course of the owner's business.

EDTI is a designated owner of a public utility pursuant to section 1(1)(n) of the *Public Utilities Designation Regulation*. Accordingly, section 101(2)(d) applies to EDTI.

AUC Findings

Ordinary Course of Business

The AUC noted that section 101(2)(d) of the *Public Utilities Act* prevents a designated owner of a public utility from disposing of assets outside the ordinary course of the owner's business without first obtaining the approval of the AUC. Any disposition without such prior approval is void.

In Order U2001-196, the AUC's predecessor outlined the criteria to be used in determining whether the disposition of an asset should be treated as being outside the ordinary course of business, as follows:

> … The Board confirms that it must first determine whether the disposition of an asset is outside the ordinary course of business for a utility. The proceeds of disposition, NBV [net book value], frequency and type of sale would be among the factors considered by the Board in that determination. The quantum, and materiality (in relation to the total rate base) of the proceeds of disposition and the NBV would all be considered. For example in this case, the NBV of $2,163,801 would be at the bottom end of the range of dispositions the Board would consider as outside the ordinary course of business. With respect to the frequency and type of sale the Board does not agree with NGTL [NOVA Gas Transmission Ltd.] that acquiring and divesting regional service centres, maintenance facilities, and field offices are necessarily in the ordinary course of NGTL's business. The Board considers that NGTL's ordinary business is the owning and operating of a pipeline, not the acquiring and divesting of real estate.
>
> … The final determination whether a disposition is outside the ordinary course continues to rest with the Board.

The AUC agreed with the principle outlined by the board in Order U2001-196 that the ordinary business of a utility is not the acquiring and divesting of real estate. The AUC found that EDTI's proposed sale of the STC property was outside the ordinary course of EDTI's business and the disposition required AUC approval under section 101(2)(d) of the Public Utilities Act.

Materiality

The AUC stated that, concerning the criterion of materiality, which is one of the factors identified in Order U2001-196, the materiality of the transaction, in part, relates to the proceeds of disposition in relation to the total rate base.

EDTI submitted that the estimated sale price of the assets under consideration in this application of $1.80 million is consistent with the range of values in dispositions previously approved by the AUC as outside the ordinary course of EDTI's business.

The AUC noted that dispositions approved by the AUC have ranged from a sale price of $0.10 million to $2.26 million. The AUC considered that the amount of the disposition for the STC property is material in respect of the sale price and the net sale proceeds based on the amounts provided in the application.

Frequency

Other criteria identified in Order U2001-196 include frequency of the disposition and the type of sale. EDTI stated it engages in these types of transactions infrequently and only when a property is no longer required for its ordinary course of business, which is the provision of electric utility service.

EDTI explained that eight applications for disposition have been approved or applied for since 2006, yielding a ratio of one disposition every 1.8 years during that period. As discussed in Proceeding 25442, EDTI Substation Disposition, four more EDTI substations are anticipated to be decommissioned in the next three years. Assuming each one results in a disposition application, it would lower the aforementioned ratio to one disposition every 1.4 years.

The AUC stated that assuming that four more disposition applications will be received by EDTI in the next three years for 5-kV substation dispositions, from the period of 2017 to 2023, the ratio will be approaching 1.0 disposition application per year. This level of frequency shows that these transactions are not infrequent. In the future, similar disposition applications may be considered to be within the ordinary course of business, as a more common occurrence for EDTI.

Assessment of Harm

In deciding whether to approve a disposition application that is outside the ordinary course of business under section 101(2)(d) of the *Public Utilities Act*, the AUC and its predecessor have traditionally applied a "no-harm" test that considers the transaction in the context of both potential financial impacts and service level impacts, in terms of both quantity and quality, to customers.

An application of the no-harm test requires the AUC to consider whether or not the transaction will adversely affect the quantity or quality of service or customer rates.

The AUC found that, in respect of service level impacts, the STC property is no longer required for the provision of electricity service, and therefore the AUC found the proposed disposition will have no adverse effect on the quality and quantity of utility service, and the disposition will not create any adverse financial impact to ratepayers.

Concerning customer rates, the AUC found that, given that EDTI is proposing to dispose of the STC property at its fair market value and that ratepayers will bear no costs arising from its disposal, including costs for environmental assessment and remediation costs, land appraisal fees, land agent fees, and legal fees will be absorbed by the utility, the disposition of the STC property will not result in harm to customers. The AUC noted that the STC property is no longer required for the provision of electricity service and will be removed from rate base effective December 31, 2022.

The AUC found that the proposed disposition of the STC property satisfies the no-harm test.

Adjustment Due to Disposition

In the application, EDTI stated that "If the application is approved, and to the extent it is consistent with the method of rebasing chosen by the AUC for the next generation of PBR for EDTI, EDTI proposes to remove the property from its rate base prior to the end of the current PBR term."

The AUC noted that is was concerned about the timing of when EDTI management determined the STC property ceased to be used for the provision of electrical utility service. EDTI has been warned by the AUC previously on requiring too much time to decide on the disposition of assets. Had the STC property been found to be no longer required for utility service in 2017, when EDTI had vacated the property, its capital costs should not have been reflected in EDTI's performance-based regulation ("PBR") rates during the current term of 2018-2022. The AUC considered EDTI's reasons as to why it waited until 2020 to bring this disposition application forward:

(a) EDTI had only recently determined that the STC property would not be required for EDTI's utility operations in the future, as EDTI had not yet determined its ongoing need for other operations centres.

(b) The current use of the STC property would conclude at the end of this year. The current use included in-class training programs, which are attended by EDTI employees. EDTI stated these courses, such as safety training, mental health awareness training, and fleet services training continues to be required to ensure that EDTI's employees are competent to carry out their duties, which is, in turn, required to ensure that EDTI meets its statutory obligation to provide safe, reliable and economic utility service, and complies with its obligations as an employer in Alberta. EDTI stated that at the end of 2020, it would no longer conduct these training programs from the STC property.

The AUC considered these reasons for delay were not fully persuasive. However, the AUC weighed the minor rate impact of rebating to ratepayers a relatively small amount of return on rate base in question (approximately $30,000 per year), against the predominant goal of reducing regulatory burden and streamlining regulatory proceedings. The AUC decided that it would not create a further regulatory process to alter the date of removal of the property from utility service to an earlier year.

The AUC considered that removal of assets from rate base at the end of the PBR term would be consistent with the AUC's findings in other EDTI disposition applications. Due to EDTI's lack of use of the STC property, the timing of EDTI's application, and given that the PBR term is set to expire at the end of 2022, EDTI's proposal to remove the net book value of the STC property from rate base on December 31, 2022, is consistent with past directions. Accordingly, the AUC directed EDTI to remove the book value of the STC property from its rate base, effective December 31, 2022.

The AUC also found that all net proceeds of sale and any net gains arising from the disposition are to be for the account of the utility shareholders, in accordance with *Stores Block*.

EPCOR Energy Alberta GP Inc. Application for Final Review and Disposition of Regulated Rate Option Rate Cap Deferral Account, **AUC Decision 25629-D01-2020**

Rates - Regulated Rate Option Rate Cap Deferral Account

In this decision, the AUC considered an application from EPCOR Energy Alberta GP Inc. ("EEA") for disposition of its regulated rate option ("RRO") rate cap deferral account in accordance with *An Act to Cap Regulated Electricity Rates* ("*Act*") and one of its associated regulations, the *Rate Cap (Commission Approved Regulated Rate Tariffs) Regulation* ("*Regulation*"). The AUC approved the disposition of EEA's regulated rate option rate cap deferral account.

Background

During the period beginning on June 1, 2017, and ending on November 30, 2019, the *Act* imposed maximum rates for the monthly electric energy charges that EEA, as an RRO provider, could bill its RRO customers. The monthly electric energy charges during this period were determined as the lower of: (i) 6.8 cents per kilowatt-hour (kWh); or (ii) the applicable monthly amount determined in accordance with EEA's energy price-setting plan (EPSP).3 For the months during this period where the applicable monthly electric energy charge for a rate class determined in accordance with EEA's EPSP exceeded 6.8 cents/kWh, the Government of Alberta would make payments to EEA for the difference.

In order to administer the payments from the Government of Alberta, EEA was required under the *Regulation* to establish a deferral account. EEA was required to include deferral account statements as part of the monthly electric energy charges filings it made to the AUC, even if no payment was being requested for the month.

The Role of the AUC

The AUC has oversight regarding two aspects of the RRO rate cap program. The first aspect of the program the AUC has oversight over is related to the filing of the deferral account statements by EEA and the other RRO providers each month. The second aspect was the filing of applications for the AUC's final review and disposition of the RRO providers' rate cap deferral accounts for the time period that the rate cap was in effect. This decision addressed the second aspect of the RRO rate cap program.

Section 6 of the *Regulation* sets out the requirements regarding the final review and disposition of EEA's RRO rate cap deferral account. Section 6(1) of the *Regulation* required EEA to apply to the AUC for the final review and disposition within six months after November 30, 2019.

Details of the Application and AUC Review

EEA provided a schedule as Attachment 1 to its application that included information for each of the months from June 2017 to November 2019 for each of its customer rate classes in the EPCOR Distribution & Transmission Inc. (EDTI) distribution service area and the FortisAlberta Inc. distribution service area. Attachment 1 showed: (i) the actual consumption volume in kWh; (ii) the RRO rates determined in accordance with its approved EPSP; (iii) the maximum rate of 6.8 cents/kWh; and (iv) the final calculated deferral amounts for any months where the RRO rates determined in accordance with its approved EPSP exceeded the maximum rate of 6.8 cents/kWh. The final calculated deferral amounts reported excluded the GST.

The schedule in Attachment 1 to EEA's application set out the final calculated deferral amounts for the applicable months of April 2018; July to September 2018; December 2018 to February 2019; and April to November 2019.

The AUC reviewed the monthly approved deferral account statements for all the months listed above, and it confirmed that EEA only included non-zero deferral amounts for those months, with the exception of December 2019. EEA did not receive any deferral amount payment from the Government of Alberta for December 2019.

Using information from the applicable AUC-approved monthly deferral account statements for EEA, the AUC confirmed that the final deferral amounts as calculated by EEA for each month agree to the total payment amounts for these months.

Based on its review, the AUC approved the disposition of EEA's regulated rate option rate cap deferral account. The AUC confirmed that no amount remained owing to EEA and that EEA had not been overpaid any amount.

EPCOR Energy Alberta GP Inc. Application for Review and Variance of Decision 22853-D01-2018 and Decision 24034-D01-2019 2018-2020 Regulated Rate Tariff, **AUC Decision 25540-D01-2020**

Rates - Review and Variance

In this decision, the AUC considered whether to grant a review application filed by EPCOR Energy Alberta GP Inc. ("EEA") requesting a review and variance of specific findings in Decision 22853-D01-20181 and Decision 24034-D01-2019 (the "Original Decisions"). The Original Decisions addressed an application from EEA for approval of its 2018-2020 regulated rate tariff ("RRT") non-energy charges (Proceeding 22853) and a compliance filing for that application (Proceeding 24034). EEA's review application requested that the monthly administration charge, which is the fixed non-energy RRT charge applicable to each rate class, be changed to a daily administration charge. The AUC approved the review application and varied the Original Decisions.

In addition, EEA applied for related relief from *Rule 032: Specified Penalties for Contravention of AUC Rules* because billing errors will arise from the changes to the administration charge. The AUC granted EEA's request for relief from specified penalties under Rule 032 for billing errors directly related to cancel-rebills and the change from monthly to daily administration charges.

Background

In the Original Decisions, the AUC approved EEA's monthly administration charge and a new customer information system ("CIS" or "CIS Project").

On April 29, 2020, the AUC received the review application from EEA requesting a review and variance of the Original Decisions. The review application was filed under section 10 of the *Alberta Utilities Commission Act* and *Rule 016: Review of Commission Decisions*. Although the application was filed outside of the time period for review under Rule 016, EEA stated that the CIS configuration issue giving rise to this application was only reasonably able to be identified by EEA during the detailed development and testing phases of the CIS Project.

In the review application EEA requested the replacement of the monthly administration charge with a daily charge because upon configuration and testing of the CIS, it became aware that the CIS is not designed to calculate and bill the administration charge on a monthly basis. EEA added that the CIS may be able to be customized to process a monthly administration charge, but that doing so would add at least $310,000 to the Project cost and would add delays that may jeopardize the planned October 13, 2020 implementation of the CIS.

The AUC's Review Process

The AUC's authority to review its own decisions is discretionary and is found in section 10 of the *Alberta Utilities Commission Act*. That act authorizes the AUC to make rules governing its review process and the AUC established *Rule 016* under that authority. *Rule 016* sets out the process for considering an application for review.

The review process has two stages. In the first stage, a review panel must decide whether there are grounds to review the original decision. This is sometimes referred to as the "preliminary question." If the AUC panel considering the review application (the "Review Panel") decides that there are grounds to review the decision, it moves to the second stage of the review process where the AUC holds a hearing or other proceeding to decide whether to confirm, vary, or rescind the original decision.

In this decision, the Review Panel decided both the preliminary question and the variance question, as it is permitted to do under section 8 of *Rule 016*.

Grounds for Review and Hearing Panel Findings

In its review application, EEA specifically requested the following approvals or relief from the AUC:

- approval to transition from calculating and billing its administration charge on a monthly basis to a daily basis, effective on the date when the CIS enters service and EEA commences billing RRT customers using the CIS;

- approval to modify EEA's RRT Price Schedules, which form part of its 2018-2020 RRT, to reflect the calculation of the administration charge applicable to each rate class as a daily charge, to take effect upon, and be reflected on all bills issued on and after, the in-service date of the CIS;

- approval of the method proposed by EEA to handle any under and over-billed amounts to customers arising from the implementation of the daily administration charge; and

- a determination that under and over-billed amounts (or "mismatches"), will not incur specified penalties under section 3(1) of *Rule 032*.

Review Panel Findings

Preliminary Matter - 60-Day Timeline

The Review Panel exercised its discretion to extend the 60-day timeline section 3(3) of *Rule 016* and accepted EEA's request for the AUC to consider the review and variance application. The Review Panel accepted EEA's explanation that the CIS limitation for billing of monthly administration charges was not discovered until after the 60-day review periods of each of the Original Decisions expired, and therefore, it could not have reasonably filed a review application within 60 days of the issuance of the each of the Original Decisions.

Section 4(D)(Ii) Or (Iii) Grounds – Previously Unavailable Facts or Changed Circumstances Material to the Decision

The Review Panel accepted that requested changes to the daily administration charge were warranted, and EEA's proposal was cost-effective compared to additional costs that would be incurred for alternative software solutions to retain a monthly administration charge. Section 6(e) of the *Regulated Rate Option Regulation* requires the AUC, when considering approval of a regulated rate tariff, "to examine the reasonableness of the owner's billing costs and other costs the owner's regulatory authority considers appropriate in the prevailing circumstances…." Given the benefits of the CIS Project, which was approved by the Hearing Panel in Decision 22853-D01-2018, delays to its implementation should be avoided where reasonably practicable. The Review Panel indicated it saw the merit of consistency in all three RRO providers in aligning billing administration charges based on a daily charge. The Review Panel found that variance of this charge was consistent with section 6(e) of the *Regulated Rate Option Regulation*.

The Review Panel therefore allowed EEA's request for a review because EEA demonstrated that there were previously unavailable facts or changed circumstances consistent with the review and variance requirements in section 6(3)(b) of *Rule 016*. Having met the first stage for a review, the Review Panel proceeded to the second stage of deciding whether to confirm, vary, or rescind the Original Decisions.

Variance of Decision 22853-D01-2018 and Decision 24034-D01-2019

The variance requested by EEA would allow it to convert its monthly administration charge to a daily charge. In support of the variance application, EEA stated that making the necessary customization for a monthly administration charge would add at least $310,000 to the Project cost and cause significant delays that could push back the implementation date for the CIS, causing further costs to be created. EEA added that changing to a daily administration charge would create a more accurate administration charge for customers and would be consistent with the other two major RRO providers, who also have a daily administration charge. EEA stated that the change would be revenue-neutral and would not change its approved revenue requirements, while also providing a proposal to ensure that no customer classes or individual customers will be made worse off by the change.

The Review Panel approved EEA's request for a variance to Decision 22853-D01-2018 and Decision 24034-D01-2019, which will allow EEA to implement a daily administration charge that will be reflected on all bills issued on and after the in-service date of the CIS.

Relief from Specified Penalties Under Rule 032

EEA indicated it was aware that it would be issuing incorrect bills as a result of transitioning to the CIS. EEA would be issuing bills to customers that would be correct when issued but would later require correction if a distribution system owner requested a cancel-rebill after EEA transitions to the CIS. This transition would result in unavoidable billing errors that would be contrary to section 3.4.1(2)(a) of *Rule 003* because EEA is an energy service provider that must not issue an incorrect customer bill.

The Review Panel noted that it does not typically provide rulings and determinations on events prior to their occurrences. However, given the specific circumstances of this review application, the Review Panel indicated it was willing to do so in this particular case. Accordingly, the Review Panel indicated it would not issue notice of specified penalties under section 63.1 of the *Alberta Utilities Commission Act* or section 3(1) of *Rule 032* for contraventions arising out of the change to a daily administration charge upon implementation of the CIS and relating to under-billed and over-billed amounts, also referred to by EEA as "mismatches" in billing amounts. However, the Review Panel also noted that should it receive complaints from customers that demonstrate that EEA has not dealt with incorrect bills arising from transitional cancel-rebills in the manner proposed by EEA and approved in this decision, EEA may be subject to specified penalties.

Decision

The Review Panel granted EEA's application for a variance.

The method proposed by EEA to handle any under-billed and over-billed amounts to customers arising from the implementation of the daily administration charge was approved, as filed. With respect to EEA's request for an exemption from specified penalties, the Review Panel found that given the specific circumstances of this request and EEA's proposed plan to mitigate any potential harm to customers, granting the exemption as requested was warranted.

***FortisAlberta Inc. Purchase Price Consideration for Transfer and Sale of the Town of Fort Macleod Electric Distribution System to Fortis*, AUC Decision 23972-D01-2020**

Electricity - Purchase Price Consideration - Transfer and Sale of Electric Distribution System

In this decision, the AUC considered a FortisAlberta Inc. ("Fortis") application to recover the acquisition costs for the purchase of the Town of Fort Macleod's ("Fort Macleod" or "Town") electric distribution system (the "transaction") through rates. The AUC found the replacement cost new less depreciation ("RCN-D") valuation methodology to be reasonable in the circumstances.

Background

On October 12, 2018, Fortis filed an application seeking AUC approval to recover the acquisition costs for the purchase of Fort Macleod's electric distribution system, pursuant to the terms of a March 12, 2018 asset purchase agreement between the two parties. Fortis determined the $4.69 million purchase price associated with the transaction by applying the RCN-D valuation methodology. The purchase price was calculated as the difference between the RCN value, calculated as $8.84 million, and the D value, calculated as $4.15 million.

Discussion

Is Use of RCN-D to Determine the Purchase Price Reasonable in the Circumstances?

Fortis determined the $4.69 million purchase price associated with the transaction by applying the RCN-D valuation methodology.

Interveners recommended utilizing the net book value ("NBV") approach as an alternate technique of valuing the purchase price for Fort Macleod's electric distribution system assets. The AUC acknowledged that the NBV, if properly derived based on accounting principles, can provide for a reasonable accounting of the historical costs incurred by Fort Macleod. However, the AUC had reservations regarding the adequacy of the derived NBV information provided by Fort Macleod. While Fortis was provided with certain basic financial information related to the operation of Fort Macleod's electric distribution system, Fortis stated that Fort Macleod was "unable to provide the Company [Fortis] with documentation related to the past or current operation and maintenance of its electric distribution system e.g., maintenance logs or asset records." The AUC stated that, in its view, the absence of good documentation practices indicates a material risk that implemented maintenance (if any) and associated expense was not adequately accounted for, resulting in the incompleteness of not only maintenance records, but also financial documentation of maintenance.

The AUC found that Fortis provided sufficient evidence to demonstrate that the RCN-D methodology, as utilized by Fortis, was a reasonable approach in valuing the electric distribution system assets in the context of the transaction between Fortis and Fort Macleod. While Fortis had not previously maintained and operated these assets, and therefore did not have historical asset records or past knowledge of the systems and information available, the AUC considered that Fortis's approach, which included a comprehensive on-site assessment of Fort Macleod's system, and application of Fortis's unit-based estimating tool, based on current construction and engineering standards with an associated labour cost, to be reasonable for calculating the purchase price of Fort Macleod's electric distribution system in the circumstances. The AUC noted that a key consideration for its finding was the absence of any other valuation methodology on the record of this proceeding that the AUC considered could have been reasonably applied in this instance.

Does the Specific Calculation of RCN-D Require Adjustment?

In the event that the AUC approved the RCN-D valuation as reasonable, interveners submitted that adjustments to the D component were necessary.

While the AUC considered that there was potential merit to an adjustment to RCN-D to account for future liabilities associated with asset removal and site restoration, the AUC indicated it was unable to find in this proceeding that an adjustment should be made. In particular, the AUC emphasized the uncertainty regarding the scale of future liabilities of this transaction. The AUC ultimately found no reasonable basis to apply any incremental adjustments to the applied for RCN-D amount.

***Imperial Oil Limited Industrial System Designation for the Imperial Oil Strathcona Refinery*, AUC Decision 25559-D01-2020**

Industrial System Designation

In this decision, the AUC considered an application from Imperial Oil Limited ("Imperial") for an industrial system designation ("ISD") at the Imperial Oil Strathcona Refinery ("Refinery"). The AUC found that the application met the applicable requirements for an ISD and that approval was in the public interest.

Background

Imperial owns and operates a Refinery at its Imperial Oil Strathcona Refinery industrial complex. Under Approval 24999-D02-2019, Imperial had approval to construct and operate a 43-megawatt (MW) cogeneration power plant (power plant) within the Refinery but had not yet constructed the power plant.

On May 12, 2020, Imperial filed an application with the AUC pursuant to section 4 of the *Hydro and Electric Energy Act*, in which it requested an ISD encompassing all of Imperial's facilities at the Refinery. The industrial system would be comprised of the previously approved cogeneration power plant and the existing 13.8-kilovolt (kV) distribution system, both located within the Refinery.

AUC Findings

The AUC explained that it must consider the ISD application in accordance with the principles and criteria set out in section 4 of the *Hydro and Electric Energy Act*.

Subsection 4(2) lists the principles the AUC must consider:

- the ISD must be consistent with the objective of giving appropriate economic signals such that industrial processes will develop their own internal electricity supply where that is the most economical source of generation;

- the ISD must support the efficient exchange of electric energy that is in excess of the industrial system's own requirements with the interconnected electric system and improve voltage stability and reduction of losses and congestion of transmission lines;

- the ISD should not facilitate "the development of independent electric systems that attempt to avoid costs associated with the interconnected electric system" and uneconomical bypass of the interconnected electric system; and

- duplication of the interconnected electric system must be avoided where it is more economical to use utility-owned transmission or distribution facilities existing in the service area where the industrial system will be located.

The AUC was satisfied that approval of the application was consistent with the principles set out above. Having reviewed the economics, the AUC found that Imperial's proposal to use an internal supply of generation represented the most economical source of generation. While Imperial asserted that it rarely proposed to exchange excess electricity given its internal process and electricity requirements, the AUC was satisfied that the proposed ISD would support such an exchange with the interconnected system. The AUC also accepted Imperial's submission that the Project would help reduce congestion while improving the region's voltage stability. Finally, the AUC found that the Project would supply a substantial portion of the Refinery's energy requirement while utilizing Imperial's existing distribution system and that approval of the proposed ISD would not result in an uneconomical bypass of the Alberta Interconnected Electric System.

The AUC also considered the application in light of the criteria found in subsection 4(3) of the *Hydro and Electric Energy Act*. The AUC was satisfied that subsection 4(3)(a) had been met. The Refinery would include a previously approved generating unit in the form of a cogeneration power plant that would produce electricity and steam to be used in the industrial operations of the Refinery. Subsection 4(3)(b) had also been met because the industrial operations would utilize several raw materials to produce various petroleum products.

Imperial would be the sole owner of all the components of the industrial operation. The AUC therefore found that subsection 4(3)(c) had been met.

Under normal operating conditions, both the electric energy and steam produced by the power plant would be used entirely by Imperial's industrial operation and each was necessary for Imperial to create its final products. The AUC was satisfied that power would be exported to the AIES only in operational downtime, including planned or unplanned circumstances where the system's normal operations are disrupted or curtailed. The AUC was therefore satisfied that the outputs of the components of the industrial operation would be used by the industrial operation, and that subsection 4(3)(d) has been met.

The AUC found that subsection 4(3)(e) had been met as Imperial owns and operates both the power plant and the Refinery. Hence, there is a high degree of integration of management of both the components and the processes of the industrial operations.

The AUC found that the cogeneration power plant demonstrated a significant investment and represents both an extension of Imperial's industrial operations processes and additional development of the electricity supply. Accordingly, the AUC was satisfied subsection 4(3)(f) had been met.

The AUC found that subsection 4(3)(g) was not applicable because the industrial operations did not extend beyond the Refinery's contiguous property.

Subsections 4(4) and 4(5) set out further criteria for the AUC to consider when it is not satisfied that a project met certain of the criteria set out in subsection 4(3). Because the AUC was satisfied that the Project met the criteria set out in subsection 4(3) it was unnecessary to assess the Project under the further criteria set out in subsections 4(4) and 4(5).

Having considered the applicable principles and criteria set out in section 4 of the *Hydro and Electric Energy Act*, the AUC found that Imperial's proposal met all the requirements for an ISD.

***Rocky View County Water Franchise Agreement with Calalta Waterworks Ltd.*, AUC Decision 25652-D01-2020**

Water Franchise Agreement

In this decision, the AUC considered an application made pursuant to section 45 of the *Municipal Government Act* by Rocky View County ("Rocky View") for approval of a water franchise agreement ("Agreement") with Calalta Waterworks Ltd. ("Calalta") for a term of 20 years.

AUC Findings

The AUC stated that franchise agreements must be approved by the AUC under section 45 of the *Municipal Government Act*:

> **Granting rights to provide utility service**
>
> 45(1) A council may, by agreement, grant a right, exclusive or otherwise, to a person to provide a utility service in all or part of the municipality, for not more than 20 years.
>
> (2) The agreement may grant a right, exclusive or otherwise, to use the municipality's property, including property under the direction, control and management of the municipality, for the construction, operation and extension of a public utility in the municipality for not more than 20 years.
>
> (3) Before the agreement is made, amended or renewed, the agreement, amendment or renewal must
>
> > (a) be advertised, and
> >
> > (b) be approved by the Alberta Utilities Commission.
>
> (4) Subsection (3)(b) does not apply to an agreement to provide a utility service between a council and a regional services commission.
>
> (5) Subsection (3) does not apply to an agreement to provide a utility service between a council and a subsidiary of the municipality within the meaning of section 1(3) of the *Electric Utilities Act*.

Section 106 of the *Public Utilities Act* requires a public utility to obtain approval from the AUC before its franchise agreement is valid:

> **Municipal franchises**
>
> 106(1) No privilege or franchise granted to an owner of a public utility by a municipality within Alberta is valid until approved by the Commission.
>
> (2) Approval may be given when, after hearing the parties interested, or with the consent of the parties, the Commission determines that the privilege or franchise is necessary and proper for the public convenience and properly conserves the public interests.
>
> (3) The Commission may, in so approving, impose any conditions as to construction, equipment, maintenance, service or operation that the public convenience and interests reasonably require.

Based on this legislation, the AUC indicated that to approve the Agreement it must consider the following issues:

(a) has the proposed franchise agreement been duly advertised?

(b) is the franchise agreement for not more than 20 years?

(c) is the franchise necessary and proper for the public convenience?

(d) does the franchise properly conserve the public interest?

Rocky View advertised the proposed Agreement in the online publication of the Rocky View Weekly Newspaper and Rocky View's website on May 7, 2020. Additionally, the AUC issued notice of the application on the AUC's website on June 10, 2020. The AUC found that the advertising completed by Rocky View and the AUC was sufficient to meet the test of the franchise agreement being duly advertised.

The AUC found that the term of the Agreement was for a maximum of 20 years and, accordingly, fell within the specified time frame.

Under the Agreement, the obligation to service the lands contained within the franchise area lies with Calalta, who is the owner of the system or works to be constructed throughout the franchise area. Failure to comply with or perform the terms of the Agreement may result in default and termination of the franchise agreement, and/or the performance of obligations in default by Rocky View, which are to be funded by the security under the franchise agreement. The AUC considered that these safeguards included in the Agreement would protect customers and conserve the public interest.

Rocky View has given first reading to Bylaw No C-8015-2020, which prohibits any person other than Calalta from providing all or any portion of the water services within the franchise area. The AUC considered this enactment would facilitate the orderly development of the franchise area, provide quality servicing, and rate certainty to customers. The AUC found this was proper for the public convenience and would conserve the public interest. Further, the Agreement would establish sufficient operational and maintenance requirements that would govern Calalta. These safeguards would also protect customers and conserve the public interest.

The proposed Agreement specified an initial franchise fee equivalent to zero percent of gross utility accounts collected by Calalta, with a maximum franchise fee of 10 percent. During the term of the franchise agreement, the level of the franchise fee may be changed once annually by Rocky View following consultation with Calalta. The AUC considered the initial franchise fee, which is set at $0.00, was reasonable given that it would not result in any additional costs to customers. Further, capping the franchise fee at 10 percent should not create an onerous burden on customers.

The AUC was of the view that the right granted to Calalta by Rocky View in the franchise agreement was necessary and proper for the public convenience and properly conserved the public interest. Accordingly, pursuant to section 45 of the *Municipal Government Act* and section 106 of the *Public Utilities Ac*t, the AUC approved the proposed Agreement as filed.

***Utility Payment Deferral Program: Various Applications for Funding for the Second Deferral Period*, AUC Decisions 25589-D02-2020, 25568-D02-2020, 25573-D02-2020, 25574-D02-2020, 25575-D02-2020, 25576-D02-2020, 25585-D02-2020, 25586-D02-2020, 25591-D02-2020, 25592-D02-2020, 25593-D02-2020, 25594-D02-2020, 25599-D02-2020, 25600-D02-2020, 25661-D01-2020, and 25721-D01-2020**

Rates - Utility Payment Deferral Program - Second Deferral Period

Background

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

On May 12, 2020, the *Utility Payment Deferral Program Act* ("*UPDP Act*") was enacted to enable electricity service providers, gas service providers, and gas transmission providers to fulfill their obligations pursuant to the Utility Payment Deferral Program.

The AUC established two deferral periods for electricity service providers, and gas service providers to submit their applications for approval for funding for bill payment amounts deferred by their eligible electricity or gas customers. The first application deadline was May 22, 2020, and covered deferred billing amounts for the period March 18, 2020, to May 8, 2020 (“first deferral period”). The second application deadline was July 10, 2020, and covered deferred billing amounts for the period May 9, 2020, to June 18, 2020 (“second deferral period”).

On May 28, 2020, the AUC issued decisions approving funding for the first deferral period for certain electricity and gas service providers. The following electricity and gas service providers requested approval for funding for the second deferral period by the July 10, 2020 deadline:

(a) 1772387 Alberta Limited Partnership (Encor);

(b) Access Gas Services Inc.;

(c) Alberta Co-operative Energy;

(d) Campus Energy Partners LP;

(e) Direct Energy Marketing Limited;

(f) ENMAX Energy Corporation;

(a) Gas Alberta Energy;

(b) Just Energy Alberta L.P. and Hudson Energy Canada Corp.;

(c) Link Energy Supply Inc.; and

(d) Utility Network & Partners Inc.

AltaGas Utilities Inc. and ATCO Gas Ltd. filed applications for deferral accounts but did not apply for funding for either the first or second deferral period. ATCO Energy Ltd. and EPCOR Energy Alberta GP Inc applied for deferral accounts and funding for the first deferral period but advised the AUC they did not require funding for the second deferral period.

The following electricity service providers filed a single application for funding for both the first deferral period and the second deferral period, and approval to establish deferral accounts for the administration of the deferred bill payments:

(a) Battle River Cooperative REA Ltd.; and

(b) Blue Mountain Power Co-op.

<u>AUC Findings</u>

Applications for Funding

Pursuant to Section 4 of the *UPDP Act*, an eligible electricity customer may enroll in a bill payment deferral program with their electricity service provider. The AUC found that the entities applying were electricity service providers with eligible electricity customers enrolled in the Utility Payment Deferral Program.

Pursuant to subsection 8(1) of the *UPDP Act*, an electricity service provider with enrolled electricity customers may apply to the AUC for funding from the Balancing Pool for the deferred bill payment amounts, other than for the portion of the electricity bill payment amounts that relate to transmission charges. The AUC approved the funding application and requested funding amounts for the electricity service providers.

Pursuant to Section 14 of the *UPDP Act*, an eligible gas customer may enroll in a bill payment deferral program with their gas service provider. The AUC found that the entities applying were gas service providers with eligible gas customers enrolled in the Utility Payment Deferral Program.

Pursuant to Section 18 of the *UPDP Act*, a gas service provider with eligible enrolled gas customers may apply to the AUC for a loan from the Minister for the gas bill payment amounts deferred by enrolled eligible gas customers, other than the portion of the gas bill payment amounts that relate to transmission charges. The AUC approved the loan applications from the gas service providers.

Deferral Accounts of Battle River Cooperative REA Ltd. and Blue Mountain Power Co-op

In section 7 of the *UPDP Act*, the AUC may approve deferral accounts for the purposes of the administration of payments for the Utility Payment Deferral Program for regulated rate providers.

Exercising its discretion, the AUC found that it was not reasonable for it to approve Battle River Cooperative Ltd. or Blue Mountain Power Co-op's request for a deferral account for the administration of payments under the *UPDP Act*. The AUC stated that this finding was consistent with the preamble and definition of electricity service provider enumerated in section 2(1)(c) of the *UPDP Act*, which distinguishes between an RRO provider and a rural electrification association. The AUC explained that it does not oversee Battle River Cooperative Ltd. or Blue Mountain Power Co-op's tariffs for its regulated rates or its contracted rates because the governing regulatory authority is prescribed in the *Rural Utilities Act*.

The AUC also found that neither Battle River Cooperative Ltd nor Blue Mountain Power Co-op had provided reasons in their applications regarding why a deferral account was required for the administration of the deferred payments under the Utility Payment Deferral Program, or why the AUC should consider its request for a deferral account under section 7 of the *UPDP Act*.

CANADA ENERGY REGULATOR

***Many Islands Pipe Lines (Canada) Limited Application for the Pierceland Supply Project Under Section 58 of the National Energy Board Act*, CER Decision File OF-Fac-Gas-M182-2019-02 01**
Facilities -

In this decision, the CER considered an application from Many Islands Pipe Lines (Canada) Limited ("MIPL(C)L") for the Pierceland Supply Project ("Project"). The CER approved the Project.

Transitional Provisions

On 28 August 2019, the *Canadian Energy Regulator Act* (the "*CER Act*") came into force and the National Energy Board ("NEB") became the CER. Section 36 of the transitional provisions associated with the *CER Act* states that applications pending before the NEB immediately before the commencement day are to be taken up before the CER and continued in accordance with the *National Energy Board Act* ("*NEB Act*").

Project Overview

MIPL(C)L applied pursuant to section 58 of the *NEB Act* for an exemption from the provisions of sections 30, 31, and 47 of the *NEB Act*, the effect of which is to approve the construction and operation of the Project.

The Project would be located on both Crown and freehold land crossing the Alberta/Saskatchewan border. The proposed pipeline route would parallel the existing Alberta Border – Beacon Hill pipeline for the majority of the route where the total land area for the pipeline right-of-way ("ROW") is 77.639 ha. The new permanent ROW would be 26 m wide. The compressor station would be located on 2.661 ha of leased Saskatchewan provincial Crown land. An access road will also be required and will lease 0.358 ha of Saskatchewan provincial Crown land. Temporary workspace ("TWS") will be required for the construction of the Project.

MIPL(C)L stated that the purpose of the Project is to meet demand. A supply expansion is required to meet customer requirements and future-dated transportation contracts. Delivery demand growth in northwest Saskatchewan is forecasted to continue for the next five to ten years and declining Saskatchewan gas production is further increasing requirements for Alberta supply imports.

Assessment of the Application

Engineering Matters

In its original application, MIPL(C)L proposed crossing two unnamed creeks via horizontal direction drilling ("HDD") and provided preliminary HDD drawings for additional details. Later, in its second supplemental filing, MIPL(C)L provided an HDD Feasibility Report for the two unnamed creeks. MIPL(C)L also proposed using HDD or a trenchless uncased crossing method to cross roads.

MIPL(C)L requested exemption from the provisions of section 47 of the *NEB Act*, namely the requirement to apply for Leave to Open ("LTO"). MIPL(C)L stated that exemption from this requirement would provide maximum flexibility to MIPL(C)L for timing of construction of the pipeline and compressor station, and the associated tie-ins. Additionally MIPL(C)L requested that if exemption to section 47 of the *NEB Act* is not granted for the entire Project, that the Project be separated into individual LTO phases, which would support the scheduling of outages needed to minimize their duration and impact to MIPL(C)L's shipper.

The CER denied MIPL(C)L's request for exemption from the requirement to apply for LTO pursuant to section 47 of the *NEB Act*, and reminded MIPL(C)L to make such application to the CER pursuant to section 213 of the *CER Act* prior to the facilities being placed in operation. The CER explained that, for clarity, MIPL(C)L has the option to apply for LTO in phases as it sees fit and the CER will consider each application separately.

Public Engagement and Land Matters

MIPL(C)L stated that the Project would require the acquisition of approximately 101.4 ha of new permanent land rights. TWS for soil storage, access, and general construction activities would require approximately 42.54 ha of land. The pipeline would be placed in a new 26 m wide ROW, which would parallel the existing Alberta Border – Beacon Hill pipeline for the majority of the route (where possible) as well as Highway 55 in Saskatchewan.

The CER noted that routing decisions involve the consideration of many factors, including environmental, archaeological, and engineering factors, as well as consultation with landowners, provincial governments, municipalities, and Indigenous peoples. The CER indicated it appreciates and acknowledges MIPL(C)L's efforts to minimize the potential environmental impact of the Project by proposing a route that parallels existing ROWs, and minimizes the taking up of new lands wherever practicable. The CER found that MIPL(C)L's route selection, land requirements, and land acquisition process are acceptable for the scale and scope of this Project.

The CER was of the view that MIPL(C)L adequately and appropriately identified stakeholders and potentially affected landowners, as well as developed appropriate engagement activities. The CER recognized that MIPL(C)L engaged landowners along the proposed pipeline route and considered their input, resulting in two instances where landowner routing concerns were accommodated.

The CER also noted that MIPL(C)L committed to continuing negotiations with property owners or occupants to resolve issues including after construction of the Project is complete.

Engagement with Indigenous Peoples

MIPL(C)L stated that it identified potentially affected Indigenous communities based on the location of the Project within asserted traditional territories, regional boundaries, and/or areas of interest. MIPL(C)L used desktop research supplemented by its own experience in working with Indigenous communities on other projects in the area as well as feedback from the Alberta Consultation Office. MIPL(C)L also contacted the NEB on January 30, 2019, to request a Traditional Territory Analysis to provide a list of potentially impacted Indigenous communities.

The CER stated that, in contrast to other project applications of a similar nature recently considered, the CER took note of MIPL(C)L's efforts at engagement and meaningful interaction with Indigenous parties in this proceeding, such as benefits and consultants agreements made, its willingness to amend its standard-form agreements, its willingness to work with Indigenous peoples to develop protocols that identify the rights and responsibilities of Elders and Monitors, and its commitment for involvement of Indigenous monitors during lifecycle stages of the Project. The CER indicated it looks forward to continuous efforts from MIPL(C)L to reduce impacts on the rights and interests of Indigenous peoples.

The CER was of the view that an approval of this Project was consistent with section 35 of the *Constitution Act*, 1982 and the honour of the Crown.

Environmental Matters

The Project would involve the construction and operation of approximately 30.3 km of new pipeline and a new compressor station. It would be located in both the Rural Municipality of Beaver River No. 622 (Saskatchewan) and the Municipality District of Bonnyville No. 87 (Alberta) on a mix of private land, Crown land, and road allowances.

The CER assessed the environmental effects of the Project and found that based on the information provided by MIPL(C)L in its application and subsequent filings, and taking into account the mitigation proposed by MIPL(C)L and the conditions imposed by the CER, that residual effects of the Project on the environment were likely to be localized to the Project development areas and reversible in the medium term. Therefore, the CER determined that Project effects on the environment were not likely to be significant.

The CER also considered MIPL(C)L's cumulative effects assessment and noted that there are existing and proposed projects and activities that have the potential for spatial and temporal interaction of Project effects, and therefore the potential for cumulative effects, including agriculture; energy transmission; oil and gas; industrial; settlement and rural and urban development; and transportation and infrastructure. Although there were possible cumulative effects for several biophysical elements, the CER was of the view that these cumulative interactions and effects are limited to the duration of construction, are fairly localized, and are minor in nature. The CER was of the view that any potential cumulative effects would also be mitigated by MIPL(C)L's environmental protection and mitigation measures. Therefore, the CER concluded that the Project would not likely result in significant adverse cumulative effects.

The CER was further of the view that a robust post-construction environmental monitoring program would be key to MIPL(C)L ensuring that potential adverse effects of the Project have been effectively mitigated and, where issues are identified post-construction, requiring that MIPL(C)L implements measures to address them. To be satisfied that post-construction environmental monitoring is thorough and the CER directed MIPL(C)L 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.

NOVA Gas Transmission Ltd. Application for the Saddle Lake Lateral Loop (Cold Lake Section) Under Section 58 of the National Energy Board Act and Section 45.1 of the Canadian Energy Regulator Onshore Pipeline Regulations, **CER Decision File OF-Fac-Gas-N081-2019-11 01**
Facilities - Gas Pipeline - Project to Support Increase in Delivery Transportation

In this decision, the CER considered an application from NOVA Gas Transmission Ltd. ("NGTL") for the Saddle Lake Lateral Loop (Cold Lake Section) (the "Project"). The CER approved the Project.

Transitional Provisions

On 28 August 2019, the *Canadian Energy Regulator Act* (the "*CER Act*") came into force and the National Energy Board ("NEB") became the CER. Section 36 of the transitional provisions associated with the *CER Act* states that applications pending before the NEB immediately before the commencement day are to be taken up before the CER and continued in accordance with the *National Energy Board Act* ("*NEB Act*").

Project Overview

NGTL applied pursuant to section 58 of the *NEB Act* for an exemption from the provisions of sections 30(1)(a) and 31 of the *NEB Act*, the effect of which is to approve the construction and operation of the Project. In addition, NGTL applied, pursuant to section 45.1 of the *Canadian Energy Regulator Onshore Pipeline Regulations* ("*OPR*"), for the replacement of the existing Cold Lake Border ("CLB") Sales Meter Station and the decommissioning of additional assets.

The Project would be located both on Crown and freehold land south of Cold Lake, Alberta. The proposed NPS 20 SLL Loop would parallel and partially overlap the existing NPS 10 SL Lateral and would partially overlap the existing right-of-way ("ROW") for 80 percent of its length. The new permanent ROW would range from approximately 11 m to 27 m. The NPS 20 SLL Loop will require the acquisition of approximately 31.3 ha of new permanent land rights. Replacement of the CLB Sales Meter Station would require 0.3 ha of freehold land. The existing fence line at the co-located sales meter stations would be expanded by approximately 33 m x 72 m to accommodate the CLB Sales Meter Station replacement component. Approximately 61 ha of temporary workspace ("TWS") would be required for the Project.

NGTL indicated that the purpose of the Project is to provide transportation and metering facilities to transport and measure sweet natural gas to meet a customer's increased delivery transportation service contract requirement.

Assessment of the Application

Land Matters

The CER indicated it acknowledges and appreciates NGTL's efforts to minimize the potential environmental impact of the Project by proposing a route that parallels existing right of ways ("ROWs"), and minimizes the taking up of new lands wherever practicable. The CER found that NGTL's route selection, land requirements, and land acquisition process were acceptable for the scale and scope of this Project.

Public Engagement

The CER was of the view that NGTL adequately and appropriately identified stakeholders and potentially affected landowners, as well as developed appropriate engagement materials. The CER was also of the view that NGTL's design and implementation of engagement activities for the Project were adequate given the scope and scale of the Project. The CER noted NGTL's commitments to continue engaging landowners through its Public Awareness Program throughout the lifecycle of the Project.

Engagement with Indigenous Peoples

The CER considered the following factors when evaluating the adequacy of consultation and accommodation: NGTL's route selection; the scope and scale of the Project; NGTL's engagement 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; participation opportunities for Indigenous peoples; NGTL's proposed mitigation measures including Horizontal Directional Drilling; commitments made by NGTL throughout the process; and conditions imposed by the CER. As a result, the CER found that there was adequate consultation and accommodation for the CER's decision on this Project. The CER was of the view that any potential Project impacts on the rights and interests of affected Indigenous peoples, after mitigation, were not likely to be significant and could be effectively addressed. The CER was of the view that approval of this Project was consistent with section 35 of the *Constitution Act*, 1982 and the honour of the Crown.

Environmental Matters

The Project would be located in a predominantly agricultural landscape with approximately 56.2 ha (60.1%) of the Project footprint being already disturbed (e.g., agriculture, anthropogenic disturbances). The footprint of the proposed NPS 20 SLL Loop would be comprised of 39.3 percent of native vegetation including forest and wetlands.

The CER was of the view that NGTL's proposed mitigation measures would sufficiently avoid or minimize the Project's predicted potential adverse environmental effects to the biophysical environment, including any cumulative effects. The CER was further of the view that a robust post-construction environmental monitoring program is key to NGTL ensuring that potential adverse effects of the Project have been effectively mitigated. The CER therefore directed NGTL to implement a post-construction environmental monitoring program for a five year period and submit Post-Construction Environmental Monitoring Reports to the CER.