REGULATORY LAW CHAMBERS

ENERGY REGULATORY REPORT

This blog 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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IN THIS ISSUE:

ALBERTA COURT OF APPEAL

Macdonald Communities Limited v Alberta Utilities Commission (2019 ABCA 353)

Wastewater Service Rates - Public Utility - Statutory Interpretation

In this decision, the Alberta Court of Appeal ("ABCA") dismissed Macdonald Communities Limited ("MCL")'s appeal of AUC *Decision 21340-D01-2017*, which was affirmed in *Decision 23203-D01-2018*. In doing so, the AUC affirmed the AUC finding that a "public utility" as defined in the *Public Utilities Act* ("*PUA*"), does not include wastewater or sewer services.

<u>Background</u>

MCL is a developer of the residential development Monterra at Cochrane Lakes, near Cochrane, Alberta. MCL applied to have the AUC set rates charged by a non-municipal invester-owned wastewater service provider. The AUC held in AUC *Decision 21340-D01-2017* that a "public utility" as defined in the *PUA* generally does not include wastewater or sewer services. In *Decision 23203-D01-2018*, the AUC's Review Panel affirmed this decision.

<u>Standard of Review</u>

The ABCA found that central to this appeal was the AUC's interpretation of the definition of "public utility" in its home statute, the *PUA*. The ABCA considered it clear that a standard of reasonableness applied, referring to the Supreme Court of Canada ("SCC") case of *ATCO Gas and Pipeline Ltd v Alberta (Utilities Commission)*, 2015 SCC 45 at para 26. There, the SCC noted that true questions of jurisdiction, if they exist as a category at all, are an issue unresolved by the Court and are rare and exceptional. The ABCA noted that the issues raised by the MCL were not exceptional. The determination of what constitutes a public utility for setting rates charged was therefore within the AUC's mandate and a reasonableness standard of review applied.

<u>Statutory Scheme</u>

The definition of a public utility is found in s. 1(i) of the *PUA*:

> (i) "public utility" means
>
> …
>
> (iv) a system, works, plant, equipment or service for the production, transmission, delivery or furnishing of water, heat, light or power supplied by means other than electricity, either directly or indirectly to or for the public,
>
> …

In contrast, section 112 of the *PUA*, which applies to municipally owned utilities, expands the definition of "public utilities":

> (2) In this section,
>
> ...
>
> (c) "public utility" includes, in addition to its defined meaning under section 1, a sewerage or waste management system.

<u>Did the Commission Fail to Apply or Properly Apply Principles of Statutory Interpretation?</u>

MCL argued that section 1(1)(iv) of the *PUA* does not distinguish between different types of water and that the term "transmission" suggests that "public utility" captures the transportation of wastewater away from the development. However, the ABCA found that the maxim of interpretation noscitur a sociis, to know a thing by its associates, creates a presumption that transmission should not be read in this way.

The ABCA stated that "production" "delivery" and "furnishing" have a common element, which suggests that public utilities convey water from their possession towards the possession of a consumer. Similarly, noscitur a sociis would suggest "transmission" should be limited in scope to bringing a utility into the possession of consumers. In this context, the ordinary and grammatical sense of "water" would not include wastewater being transmitted away from the development.

The ABCA found that the definition of "public utility" is further informed by section 112(2)(c) of the *PUA,* which confers additional jurisdiction to the AUC to regulate sewerage and waste management systems solely for the purpose of managing intermunicipal disputes. The ABCA stated that the two definitions of "public utility" found in the *PUA* must be read in their grammatical and ordinary sense and in a fashion that ensures coherence and consistency. The words “in addition to” signal the legislative intent that “public utility” not include sewerage or waste management systems.

The ABCA noted it is presumed that the legislature does not intend absurd consequences, and an interpretation that leads to an absurdity should be avoided. The ABCA found that MCL’s speculative argument that Horse Creek Sewer may abuse its position as the sole provider of wastewater services to the development does not give the AUC, or the ABCA, license to ignore the words of the *PUA* to prevent this contingency.

The ABCA did acknowledge MCL made a compelling argument that the AUC would better serve its public function by regulating wastewater. However, this alone was not enough to counteract jurisdictional constraints intended by the legislation.

Conclusion

The ABCA dismissed the appeal, finding the AUC’s interpretation of the definition of “public utility” was entitled to deference. MCL failed to demonstrate that that interpretation was unreasonable.

ALBERTA UTILITIES COMMISSION

Alberta Electric System Operator - 2018 Independent System Operator Tariff (AUC Decision 22942-D02-2019)

ISO Tariff

In this decision, the AUC considered whether to approve an application (the "Application") from the Alberta Electric System Operator ("AESO") regarding its 2018 Independent System Operator ("ISO") tariff. The AUC directed the AESO to refile the Application in January 2020.

<u>Legislative Scheme</u>

Section 119(4) of the *Electric Utilities Act* requires the AESO to prepare a tariff and to apply to the AUC for approval of this tariff. The tariff is composed of two elements: (i) costs and expenses; and (ii) the proposed allocation of costs and expenses to rate classes (rate design).

<u>Point of Delivery ("POD") Cost Function</u>

The POD cost function is used (i) to classify costs for the POD charge in Rate Demand Transmission Service ("DTS"); and (ii) to establish investment levels for the construction contribution policy in section 8 of the proposed ISO tariff.

The AESO considered four options for the data and variables included in the POD cost function estimation. Subsequently, in the AESO rebuttal evidence, the list of options was expanded to include five further options. The nine options were:

Table 2. POD cost function options (updated)

Option		Greenfield projects capacity	Upgrade projects capacity	Zero MW upgrade projects	Pre-AESO projects	Costs based on:
#1	As applied for in 2014 application and in the current application	Contract	Contract*	Include	Include	Participant-related costs
#2	Current practice	Contract	Contract	Remove	Include	Participant-related costs
#3	As requested in Decision 2014-242	Contract	Installed	By using installed, zero MW upgrade projects are included	Include	Participant-related costs
#4	Not asked for previously	Installed	Installed	By using installed, zero MW upgrade projects are included	Include	Participant-related costs
#4a	Option #4 with zero MW projects removed	Installed	Installed	Remove	Include	Participant-related costs
#4b	Option #4 with pre-AESO projects removed	Installed	Installed	By using installed, zero MW upgrade projects are included	Remove	Participant-related costs
#5	Combines #4a & #4b – zero MW and pre-AESO projects removed (per the DUC evidence)	Installed	Installed	Remove	Remove	Participant-related costs
#6	Create a single substation cost function such that all upgrade costs and capacity increases are combined as a single substation (per the DUC IR responses to AUC)	Installed	Installed – combine upgrades into the single substation	Remove	Remove	Participant-related costs
#7	Option 6 amended to use AESO investment amounts instead of participant-related costs.	Installed	Installed – combine upgrades into the single substation	Remove	Remove	AESO investment amounts

The AUC found that there were difficulties associated with many of the options, including option #4a which, if not for issues with the conversion from installed capacity to contract capacity, would otherwise be the AUC's preferred option. The AUC therefore found that the AESO should continue with the status quo, as reflected in option #2, based on contract capacity but excluding the zero megawatt ("MW") upgrade projects.

<u>Rates</u>

Power Factor Deficiency Charge

The AUC was not satisfied that the AESO sufficiently justified its proposed increase in the charge from $400 per Market Value Added ("MVA") to $1,200 per MVA. Given these concerns, the AESO's proposed change to the existing power factor deficiency charge to $1,200 per MVA from $400 per MVA was denied. The AUC directed the AESO to either provide further support for its calculation of the $1,200 per MVA charge in the compliance filing to this decision or its next comprehensive general tariff application.

Rate Supply Transmission Service ("STS") - Changes in Generating Unit Owner's Contribution ("GUOC") Rate Levels

The AESO proposed changes to the capacity that is used to calculate a GUOC and the method used to calculate the GUOC rate. The AESO proposed to calculate a GUOC, as follows:

(a) maximum capability of a new generating unit if only the generating unit is being added at a site; or

(b) maximum capability of a new generating unit less the minimum capacity of new load being added at the same time at the same site, or is proposed to be added within 12-months of the added generation.

No objections to the AESO's proposed changes to the capacity used to calculate a GUOC, the method used to calculate the GUOC rate, or the AESO's proposed GUOC rate were submitted. The AUC approved the AESO's proposed method to calculate the GUOC rate, and the AESO's GUOC rates.

<u>Terms and Conditions</u>

AESO Discretion to Make Contract Capacity Adjustments

The changes to the terms and conditions included discretion for the AESO to adjust existing contract capacities in the event they differ materially from actual flows to or from the transmission system (subsection 5.2(2)). Subject to directions set out in this decision, the AUC approved subsection 5.2(2).

ISO Preferred Alternative if Construction of Transmission Facilities Required

Under the AESO's proposed subsection 3.4(1), where the construction of transmission facilities is required for a connection project, the ISO must determine how to respond to the system access service request, and select the AESO's preferred connection alternative taking into account certain relevant factors. The AUC found that additional review of the provision may be of value once the AESO has had an opportunity to apply subsection 3.4(1). Accordingly, the AUC directed the AESO to work with market participants to address any concerns.

Requirement for Market Participants to Provide Specific Information in System Access Service Requests ("SASRs")

The AESO proposed revisions to subsection 3.2(2) of the current ISO tariff to require market participants to provide, in a SASR, specific information that the AESO will reply upon to plan a connection. The AUC found the AESO's proposal would add certainty to the AESO's transmission system planning process and provide increased clarity to market participants regarding the status of their proposed projects. However, the AUC noted that additional review of the provision may be of value once the AESO has had an opportunity to apply subsection 3.2(2). Accordingly, the AUC directed the AESO to work with market participants to address any concerns.

Timing of GUOC Payments

The AESO proposed that supply market participants be required to pay a GUOC within 30 days of a system access service agreement becoming effective (subsections 7.5(3) and 7.5(4)). The AUC approved subsections 7.5(3) and 7.5(4) as filed.

Classification of Connection Project

The AESO proposed several changes to its terms and conditions in how it determines the classification of a connection project as a system-related or participant-related cost.

The AUC found that the AESO's proposed subsection 4.10 may not provide adequate discretion to the AESO to vary the application of certain aspects of its tariff contribution policy when circumstances warrant. Subsection 4.10 effectively replaced the currently approved subsection 8.10. The AUC noted that by expressly providing the AESO with broad discretion in the classification of costs as between system-related and participant-related, subsection 8.10 provides a means by which the AESO can adapt unique circumstances that may not be contemplated at the time of comprehensive ISO tariff applications. Accordingly, the AUC directed the AESO to revise its proposed subsection 4.10 at the time of refiling the Application to substantially replicate the wording in the current tariff's subsection 8.10.

The AUC found the change from defining participant-related costs in relation to what constitutes a "contiguous connection project" as used in the existing tariff's subsection 8.3(2) to the proposed tariff's proposed language in subsection 4.2(2), which grants the AESO the ability to deem costs to be participant-related if the AESO considers the costs to be "necessary to accommodate a connection project," to be reasonable.

The AESO proposed to amend or remove several provisions in the current ISO tariff's terms and conditions that set out the framework for the classification of transmission project costs between system-related and participant-related. This includes costs regarding radial and looped facilities. The AUC found that it was within the scope of the AESO's mandate to propose changes to the looped vs. radial classification framework adopted in *Decision 2001-6*.

The AESO's proposed subsection 4.2(2)(1) addressed situations where existing system transmission facilities are reclassified to participant-related to meet the requirements of a connection project. The AUC found the proposed language in subsection 4.2(2)(1) was required to facilitate an equivalent comparison between old and new facilities. The AUC approved the AESO's proposed subsection 4.2(2)(1).

Distribution Connected Generation ("DCG") and AESO Adjusted Metering Practice

The AUC found that the AESO's adjusted metering practice was consistent with applicable legislation. The AUC noted that public interest considerations raised by proponents for the promotion of renewable forms of generation should not take precedence over the need to implement the AESO's adjusted metering practice to rectify billing determinant erosion and potential cross-subsidization of DCG by load. Additionally, concerns about the cost or complexity of implementing the adjusted metering practice should not preclude its approval.

Subject to any matter arising following the review of the potential effect of the AESO's adjusted metering practice to be considered in the refiling Application proceeding, the AUC approved the AESO's proposed adjusted metering practice.

AltaLink Construction Contribution Proposal

A construction contribution is the financial contribution in aid of construction ("CIAC") in excess of the available investment by the AESO that a market participant must pay for the construction and associated costs of transmission facilities required to provide system access service. Construction contributions are intended to balance the economic effects of connecting a new customer between existing customers and the new customer.

On December 15, 2017, AltaLink filed a letter in this proceeding advising that it planned to file a proposal regarding the distribution facility owner customer contribution as part of its evidence in this proceeding. Following a consultation period, AltaLink filed its evidence on January 15, 2019.

The AUC found that the adoption of AltaLink's contribution proposal could result in a material financial benefit to ratepayers and was therefore in the public interest. Accordingly, the AUC directed the AESO, in its refiling, to consult with AltaLink and for the AESO and AltaLink to provide a joint proposal for the implementation of AltaLink's contribution proposal.

<u>Order</u>

The AUC directed the AESO to refile its 2018 ISO Tariff Application to reflect the findings, conclusions and directions in this decision after January 1, 2020 but no later than January 31, 2020.

AltaLink Management Ltd. 2017-2018 General Tariff Application Negotiated Settlement Agreement Revenue Sharing (AUC Decision 24694-D01-2019)

General Tariff Application - Refund of Cost Savings

In this decision, the AUC considered an application (the "Application") by AltaLink Management Ltd. ("AltaLink") for approval to refund cost savings resulting from AltaLink's 2017-2018 General Tariff Application ("GTA") Negotiated Settlement Agreement ("NSA"). The AUC approved the Application.

<u>Background</u>

In the Application AltaLink requested approval of a one-time payment of $6.5 million arising from savings of direct Operations and Maintenance costs, direct Administrative and General costs and Revenue Offsets, to the Alberta Electric System Operator ("AESO"), pursuant to provisions of its GTA NSA under the cost savings arrangement. Further, AltaLink requested approval to increase this one-time payment to the AESO from $6.5 million to $6.6 million, to account for carrying costs, pending AUC approval of AltaLink's request for payment of interest in its 2014-2015 Deferral Account Reconciliation Compliance Filing. AltaLink requested that this payment occur on or before September 30, 2019.

The Consumer's Coalition of Alberta ("CCA") filed an argument on August 15, 2019, as directed by the AUC, identifying three areas of concern in AltaLink's 2017-2018 GTA NSA revenue sharing agreement: inclusion of short-term incentive plan ("STIP") costs above target, inclusion of safety bonuses; and AltaLink's Rule 023 interest calculation. The AUC addressed each of these concerns in its findings.

Commission Findings

Inclusion of STIP Costs Above Target

AltaLink stated that it had consistently determined both STIP and long-term incentive plan ("LTIP") calculation amounts according to past GTAs, and that the STIP amount of $0.6 million complied with and did not exceed the agreed-upon 2017-2018 GTA NSA amount. The AUC agreed with AltaLink that the STIP and LTIP calculations used to determine actual 2017-2018 LTIP and STIP payouts were consistent with how the calculations were presented in AltaLink's 2017-2018 amended GTA and was not altered in any way by the NSA. The AUC therefore approved the inclusion of the STIP amount of $0.6 million in AltaLink's revenue-sharing amounts related to the 2017-2018 GTA.

Inclusion of Safety Bonuses

The CCA requested that the AUC direct AltaLink to remove an amount of $0.3 million in safety bonuses from AltaLink's GTA NSA revenue sharing Application. The CCA submitted that AltaLink did not include the $0.3 million of safety bonuses in its applied-for revenue requirement in its 2017-2018 GTA and consequently, the AUC should deny the inclusion of these costs in the revenue sharing mechanism. The AUC considered that the NSA did not prescribe how AltaLink was to manage its agreed-upon 2017-2018 expenditures, sharing any excess reduction in costs with ratepayers, including the amount of $0.3 million in safety bonuses. The AUC therefore approved the inclusion of the $0.3 million in safety bonuses in AltaLink's revenue-sharing amounts related to the 2017-2018 GTA.

Carrying costs – Interest Payment Under Rule 023

AltaLink applied to refund $0.2 million of carrying cost interest as part of the cost savings sharing agreement refund related to its 2017-2018 GTA NSA. Rule 023 enables a utility to request that the AUC award the payment of interest on adjustments to utility rates, tolls or charges or other costs/charges administered within the AUC's jurisdiction.

The AUC found that the application of carrying costs was not warranted or reasonable in the circumstances of this case. The AUC made this finding based on (a) the expediency with which AltaLink sought to refund the revenue sharing amounts with ratepayers by making its application in 2019; and (b) the relatively low quantum of the refundable amounts ($2.9 million and $3.4 million in 2017 and 2018, respectively) and, therefore, of carrying cost interest associated with those amounts. The AUC therefore denied the addition of carrying costs from AltaLink's revenue-sharing amounts related to the 2017-2018 GTA.

Order

The AUC ordered AltaLink to:

(a) remove the carrying costs portion from the total refund amount of its 2017-2018 GTA NSA revenue sharing Application; and

(b) provide a one-time refund amount to the AESO of $6.5 million on or before September 30, 2019.

AltaGas Utilities Inc. 2019-2020 Unaccounted-For Gas Rider E and Rider H (24763-D01-2019)

Unaccounted-for Gas Riders

In this decision, the AUC approved AltaGas Utilities Inc. ("AltaGas")'s rate Riders E and H as filed, effective November 1, 2019.

Background

Riders E and H aimed to recover amounts associated with unaccounted-for Gas ("UFG"). Rider E recovered the amount of UFG associated with producer transportation service, and rider H recovered the amount of UFG associated with processes of the Natural Gas Settlement System ("NGSS").

Commission Findings

The AUC reviewed the calculations of the Rider E and Rider H to be effective beginning of November 1, 2019. The AUC was satisfied that AltaGas's proposed UFG rate calculations were accurate and consistent with the methodology approved in previous decisions.

The AUC found the currently proposed amounts to be recovered through rate Riders E and H fell within the historical range for each of the rate riders, based on the five-year historical average calculation. However, the AUC noted that the five-year averages underlying the 2019-2020 Rider E and Rider H UFG amounts had increased this year after declining for four years in a row between 2015-2019. On this point, the AUC stated that while the AUC was satisfied with AltaGas' explanations for the increase in UFG during 2018-2019, it continues to expect that UFG fluctuations and overall UFG percentages decrease over time as a result of AltaGas' ongoing initiatives and expenditures to reduce UFG.

The AUC found that AltaGas had complied with the Commission's direction in paragraph 37 of *Decision 23740-D01-2018* to:

(a) develop and provide a relative ranking of UFG causes;

(b) quantify the causes of UFG, where possible;

(c) describe the specific actions taken by AltaGas to reduce UFG fluctuations and UFG overall amounts;

(d) provide reasons for any year-over-year increases/decreases in AltaGas' UFG;

(e) update the historical data set, which spans the period for the most recent ten years of monthly data to the most current month for the receipt and delivery volumes and UFG percentage losses or gains; and

(f) provide a regional UFG breakdown and any explanation and insight gained from the regional analysis.

The AUC was satisfied that AltaGas's calculations and proposed adjustments to Rider E and Rider H were reasonable.

Order

Rider E and H rate schedules were approved as filed. AltaGas' rider E was approved at 1.10 percent and rider H at 1.11 percent, effective November 1, 2019.

ATCO Electric Ltd. Approval of Sale Offering for Palisades Power Plant (Decision 24598-D01-2019)

Sale Offering - Power Plant

In this decision, the AUC considered an application (the "Application") by ATCO Electric Ltd. ("ATCO Electric") requesting approval of the sale offering for the Palisades Power Plant, as required by section 18 of the *Isolated Generating Units and Customer Choice Regulation* ("*IGUCCR*"). The AUC approved the Application as filed.

Background

In *Decision 24183-D03-2019*, ATCO Electric was authorized to discontinue operations and to decommission and salvage the Palisades Power Plant. The AUC noted that ATCO Electric is currently in the process of decommissioning the Palisades Power Plant, approved in *Decision 24183-D03-2019*, and submitted the present Application as part of the decommissioning.

Statutory Scheme

Section 26 of the *IGUCCR* states that where an isolated generating unit is no longer required to provide electric energy as a result of an isolated community or industrial area requiring less electric energy or being connected to the interconnected electric system, the owner of the generating unit must decide whether to sell the generating unit. In cases where the owner decides to sell the generating unit, the sale must be conducted in accordance with Part 2 of the *IGUCCR*.

The AUC further noted that section 18(1) of the *IGUCCR* requires that before advertising a sale offering, the owner of the generating unit must submit to the AUC the sale offering and a proposal as to how the sale offering complies with section 17 of the *IGUCCR*. Section 18(2) of the *IGUCCR* also requires that, if on reviewing the proposal, the AUC is satisfied that section 17 will be complied with, the owner must proceed with the sale offering in accordance with the proposal.

Commission Findings

The AUC was satisfied that the sale offering was widely publicized and conducted in a way that kept the offering attractive and prevented discouragement of potential bids in response to the offering. Thereby requirements set out in section 17 of the *IGUCCR* were met. The AUC was also content that ATCO Electric submitted the sale offering and a proposal describing how section 17 of the *IGUCCR* was abided by before the offering was advertised. The AUC further noted, that no objections were raised to the proposed sale offering and its method.

The AUC was satisfied that the offering and the proposal met all applicable requirements. The sale offering, and proposal was approved as filed.

ATCO Electric Ltd. Franchise Agreement with the County of Stettler for the Hamlet of Botha (AUC Decision 24865-D01-2019)

Electricity - Franchise Agreement

In this decision the AUC considered an application from ATCO Electric Ltd. ("ATCO") for approval of an electric distribution franchise agreement ("franchise agreement") with the County of Stettler for the Hamlet of Botha. The AUC approved the franchise agreement as filed.

Statutory Scheme

Section 45 of the *Municipal Government Act* ("*MGA*") and section 139 of the *Electric Utilities Act* ("*EUA*") requires municipalities to receive AUC approval prior to entering into, renewing or amending a franchise agreement with a person to provide a utility service in the municipality.

Proposed Franchise Agreement and Franchise Fee Rate Rider Schedule

Under the proposed franchise agreement, the County of Stettler would grant ATCO the exclusive right within the municipal service area to provide electric distribution service and construct, operate, and maintain the electric distribution system. The proposed franchise agreement would have a term of ten years.

The proposed franchise fee of 0.00 percent would replace the current franchise fee of 3.00 percent, resulting in a decrease of $3.35 to the average monthly charge for an average residential customer. The proposed franchise fee would be less than the 20 percent franchise fee cap previously approved by the AUC. Under the franchise agreement, the County of Stettler would also have the option to change the franchise fee percentage annually upon written notice to ATCO and AUC approval.

The AUC found the proposed changes to the standard electric franchise agreement template provided clarity and were reasonable in the circumstances.

Conclusion

Pursuant to section 45 of the *MGA* and section 139 of the *EUA*, the AUC found the right granted by the County of Stettler to ATCO to be necessary and proper for the public convenience and that it properly serves the public interest. Consequently, the AUC approved the franchise agreement. In accordance with section 125 of the *EUA*, and given the approval of the franchise agreement in this decision, the AUC also approved ATCO Electric's rate rider A of 0.00 percent.

ATCO Gas and Pipelines Ltd. Franchise Agreement with the Town of Magrath (AUC Decision 24812-D01-2019)

Natural Gas - Franchise Agreement

In this decision, the AUC considered an application by ATCO Gas and Pipelines Ltd. ("ATCO") requesting approval of a natural gas franchise agreement ("franchise agreement") renewal with the Town of Magrath ("Magrath"). ATCO also sought approval of a franchise fee rate rider schedule, which reflected the franchise fee percentage set out in the proposed franchise agreement. The AUC approved the proposed franchise agreement and the franchise fee rate rider schedule as filed.

Proposed Franchise Agreement and Franchise Fee Rate Rider Schedule

Under the proposed franchise agreement, Magrath would grant ATCO the exclusive right within the municipal service area to provide a natural gas distribution service and construct, operate and maintain the natural gas distribution system. The proposed franchise agreement would have a term of ten years.

The proposed franchise fee of 15.00 percent was a continuation of the franchise fee from the previous franchise agreement between Magrath and ATCO. ATCO advised this would result in a continuation of an average monthly franchise fee of $6.28 for an average residential customer. Under the franchise agreement, Magrath would have the option to change the franchise fee percentage annually upon written notice to ATCO and Commission approval. The franchise fee would be a payment in lieu of municipal property taxes pursuant to section 360 of the *Municipal Government Act* ("*MGA*").

The proposed franchise agreement included changes to the standard natural gas franchise agreement template, which was approved by the AUC in *Decision 20069-D01-2015*. Language was added to *Clause 5(a) – Franchise Fee* indicating that the Parties agree that the Company (ATCO) shall pay a franchise fee in lieu of taxes on the franchise pursuant to section 360 of the *MGA*. *Clause 8 – Municipal Taxes* within the standard franchise agreement template was removed from the proposed franchise agreement.

Statutory Framework

Section 45 of the *MGA* deals with franchise agreements and provides, before such an agreement is made, amended or renewed, it must be approved by the AUC. Similarly, section 49(1) of the *Gas Utilities Act* provides that no franchise granted to any owner of a gas utility by any municipality within Alberta is valid until approved by the Commission.

In considering whether to approve the franchise agreement, the AUC must determine whether the proposed franchise agreement is necessary and proper for the public convenience, and properly conserves the public interests, as set out in section 49(2) of the *Gas Utilities Act*. Franchise agreements are reviewed from a more general perspective than a utility's costs and rates, as a municipality's council is accountable to its ratepayers for the franchise fees that it implements.

Commission Findings

The AUC noted the proposed franchise fee of 15.00 percent was below the 35 percent fee cap previously approved by the AUC and was a continuation of the franchise fee from the previously approved franchise agreement between these parties. The term of the proposed franchise agreement was within the 20-year maximum specified by the *MGA*. Magrath had been paid franchise fees in lieu of taxes in previous franchise agreements, and Magrath has this option pursuant to section 360 of the *MGA*.

The AUC found the right granted to ATCO by Magrath in the proposed franchise agreement to be necessary and proper for the public convenience and to properly conserve the public interests. The AUC therefore approved the proposed franchise agreement as filed pursuant to section 45 of the *MGA* and section 49 of *Gas Utilities Act*. In accordance with section 36 of the *Gas Utilities Act*, the AUC also approved ATCO's rate rider A amount of 15.00 percent for customers in Magrath.

Canadian Utilities Limited Application for Reorganization of Canadian Utilities Limited (AUC Decision 24716-D01-2019)

Gas & Electricity - Application for Corporate Reorganization

In this decision, the AUC considered an application (the "Application") from Canadian Utilities Limited ("CUL") to complete internal restructuring and reorganization relating to the Alberta PowerLine Limited Partnership ("APL"). The AUC approved the Application.

Statutory Scheme

CUL is a designated owner of a public utility under sections 101 and 102 of the *Public Utilities Act* ("*PUA*"), under section 1(1) of the *Public Utilities Designation Regulation* and a designated owner of a gas utility under sections 26 and 27 of the *Gas Utilities Act* ("*GUA*"), and under section 2 of the *Gas Utilities Designation Regulation*. Therefore, CUL must obtain approval or an exemption from approval from the AUC if it engages in certain transactions.

Background

APL owns and operates the Fort McMurray West 500 kV Transmission Project, which provides electric transmission service between the Edmonton and Fort McMurray regions.

CUL indirectly owns an 80 percent equity interest in APL through its ownership of four numbered companies and APL's general partner. CUL's internal reorganization is intended to achieve certain tax efficiencies and to facilitate a sale of its interest in the transmission line.

AUC Findings

The AUC noted that the central question in deciding whether to approve a transaction outside of the ordinary course of business, under sections 101(2)(d)(i) and 101(2)(d)(ii) of the *PUA*, and sections 26(2)(d)(i) and 26(2)(d)(ii) of the *GUA*, is whether customers are harmed by the transaction.

The customers in this case were the consumers of electricity and natural gas utility services.

The AUC stated that factors considered by the AUC in considering the no-harm test include:

a) customers are, to the maximum extent possible, to be protected against any negative ramifications arising from a transaction;

b) customers are not entitled to a level of post-transaction regulatory certainty they would not have realized if the transaction had not been approved; and

c) customers are at least no worse off after the transaction is completed after consideration of the potential positive and negative impacts of a proposed share transaction.

The AUC found that the proposed transactions did not have any potentially harmful operational effects on regulated customers that would impair the integrity and reliability of the electricity and natural gas systems. The ownership and operations of the utilities would not change because of the internal reorganization by CUL. Further, the internal reorganization was not anticipated to affect the credit rating for CU Inc. Additionally, there would be no cost allocation implications resulting from the proposed transactions. Transaction costs of the internal reorganization would be borne by CUL and will not be passed on through any corporate cost allocation.

The AUC concluded that approval of the Application for internal reorganization would not result in any financial harm to customers. Approval would not have a harmful effect on regulated utility service or the rates charged for those services, nor would the internal reorganization negatively affect regulatory oversight of CUL or any other designated owner. The no-harm test was therefore satisfied.

<u>Order</u>

The AUC granted approval of the applied-for share transfers and the applied-for internal restructuring and reorganization.

Consultation on the Issues of Power Plant Self-Supply and Export (AUC Bulletin 2019-16)

Consultation - Power Plant Self-Supply

The AUC concluded that Alberta legislation limits the circumstances under which the owner of a generating unit can consume electricity produced from that unit and export the electricity produced by that generating unit for exchange through the power pool. Two circumstances are:

(a) Industrial systems designated under section 4 of the *Hydro and Electric Energy Act.*

(b) A class of small generators under the *Micro-generation Regulation*.

Outside these exemptions, owners of generating units are prohibited from using that unit to supply on-site load and export electricity generated by that unit for exchange through the power pool.

The AUC indicated it recognizes the legislation was enacted prior to the recent increase in distributed generation and the availability of economic, small-scale generating units. The AUC also acknowledged it has no authority to amend the statutory scheme. However, it can seek feedback on potential amendments to the statutory scheme which it can share with the Department of Energy. The AUC indicated it would therefore be seeking feedback regarding whether, in the future, self-supply and export under the statutory scheme should remain the same, be allowed subject to limitations, or be allowed with no limitations.

The AUC set a deadline of October 11, 2019, for stakeholder comments.

Generic Proceeding to Review Rate Treatment of Distribution System Acquisition Costs Under Performance-Based Regulation (AUC Decision 24405-D01-2019)

Rate Treatment Review - Distribution System Acquisition

In this decision, the AUC considered the rate treatment of amounts paid by a distribution utility in Alberta for acquiring distribution systems owned by rural electrification associations ("REAs"), gas co-operatives and municipalities under the 2018-2022 performance-based regulation ("PBR") plan. The AUC also considered the treatment of such costs for municipality owned electric distribution systems under the 2013-2017 PBR plan.

<u>Applicable Legislative Provisions</u>

The majority of the submissions in this proceeding concerned the acquisition of distribution systems owned by REAs and municipalities by electric distribution utilities. Section 30 of the *Hydro and Electric Energy Act* provides that no person shall discontinue the operation of an electric distribution system without authorization from the AUC to do so.

Pursuant to the *Electric Utilities Act*, the AUC must ensure that the rates charged by a distribution utility are, amongst other things, just and reasonable and not unduly preferential, arbitrary or unjustly discriminatory. The AUC must also establish rates that provide an electric distribution utility with a reasonable opportunity to recover its prudent costs of providing service to its customers, including a fair return.

Basis to Distinguish Between REAs and Municipally Owned Electric Distribution Systems

The AUC found no sufficient legislative or principled basis for differentiating between the purchase of a REA from the purchase of a municipally owned electric distribution system for the purposes of funding under the 2013-2017 or the 2018-2022 PBR plan.

Rate Treatment of Acquisition Costs for Municipally Owned Electric Distribution System Under the 2013-2017 PBR Plan

The AUC accepted that at the time of the Crowsnest Pass transaction, which the AUC approved in *Decision 21980-D01-2016*, FortisAlberta Inc. ("Fortis") did not anticipate that the costs associated with the purchase of a municipally owned system would be treated differently for ratemaking purposes than the costs associated with the purchase of a REA. The AUC found this was a reasonable expectation, noting that it was consistent with the AUC's own determination in this decision that there is no sufficient legislative or principled basis upon which to distinguish between the acquisition of an REA distribution system and a municipally owned distribution system, for rate treatment purposes under PBR.

The AUC also accepted that Fortis' expectation that the costs of the Crowsnest Pass system acquisition would be eligible for a Y factor adjustment if the transaction was ultimately approved and the costs of the acquisition were determined to be prudent. A Y factor adjustment is a cost adjustment that must be approved by the AUC regarding costs incurred as a result of AUC-directed acquisitions. The AUC viewed the approvals issued in Proceeding 21785 as an AUC direction to Fortis to acquire the Crowsnest Pass system. The costs paid for that system were prudent. Therefore, Fortis would be eligible for a Y factor adjustment.

Rate Treatment of Acquisition Costs for REAs, Gas Co-operatives and Municipally Owned Electric Distribution Systems Under the 2018-2022 PBR Plan.

Rate Treatment of Acquisition Costs for Distribution Systems Under the 2018-2022 PBR Plan

The AUC disagreed with Fortis' position that the presence of an AUC direction should not be determinative of the associated rate treatment. An AUC direction remains required in order for the costs associated with the acquisitions that are the subject of this proceeding to qualify for a Y factor adjustment. That said, an application regarding the prudence of the purchase price and an application for a Y factor adjustment will no longer typically be required as these costs will be managed by the distribution utilities within the revenue provided under the 2018-2022 PBR plan and without additional regulatory scrutiny from the AUC for the duration of the existing PBR plan.

The Role of Q Factor in the Acquisition of Electric Distribution Systems or Assets

In the 2018-2022 PBR plan, the AUC continued its practice from the prior PBR term of designating the percentage change in forecast billing determinants in any given year, as a Q factor.

In its evidence, EQUS REA Ltd. explained that a distribution utility can incorporate effects of customer increases, resulting from the acquisition of an REA or municipally owned distribution system, by way of an adjustment of the Q factor.

The AUC found it was unnecessary to adjudicate the issue of whether changes to the Q factor provide an adequate source of funding for acquisitions. The AUC stated that Q factor is one component of the PBR scheme within which distribution utilities may manage voluntary, freely negotiated acquisitions going forward.

Basis to Distinguish Between REAs, Municipal Electric Distribution Systems and Gas Distribution Systems

The AUC found that insufficient evidence was provided to enable it to consider adequately the rate treatment of gas distribution system acquisitions and whether a distinction from electrical distribution system acquisitions is warranted.

Rate Treatment for the Acquisition of the Fort Macleod System

The AUC found that if the necessary approvals are issued in Proceeding 23702, the AUC would treat those approvals as the basis for an AUC direction such that the prudent costs determined in Proceeding 23972 will be eligible for a Y factor adjustment.

Streamlined Regulatory Review Process

The AUC found that if compelling circumstances are asserted and accepted by the AUC as justification for an AUC-directed acquisition, the AUC will assess any related prudency issues and rate treatment requests on a case-by-case basis. Overall, this should result in greater rate certainty, a reduction of regulatory burden, and a streamlining of the AUC's approval process for distribution system acquisitions.

New Performance Standards for Processing Facility Applications (AUC Bulletin 2019-15)

Facility Applications - Performance Standards and Timelines - Update

The AUC updated its internal performance standards and timelines for processing facility applications. The new standards and timelines replace those set out in Bulletin 2009-25, and apply to all facility applications filed on or after August 1, 2019.

While the new standards continue to recognize five categories of facility applications, the AUC refined or changed the criteria for those categories to reduce ambiguity and increase certainty. Under Bulletin 2009-25, Category 2 applications were characterized as simple applications that required notice or minimal information requests, whereas Category 3 applications were characterized similarly but with extensive information requests. Under the revised standards, Category 2 relates only to applications where notice is not required, but a single round of information requests is necessary to complete the application. Category 3 applications are now characterized by issuance of a notice and one or more rounds of information requests. The AUC redefined Category 4 and 5 applications based on the complexity of issues raised in a proceeding rather than on whether the application would be considered in an oral or written proceeding.

The AUC added new performance standards and timelines for record development, providing greater transparency and accountability for the AUC's processing of facility applications. The AUC indicated that the new record development standard will incentivize more efficient application processing by establishing standard processing steps and timelines for each application category. The AUC's new performance standards and timelines are now more category specific, including a 90 percent record development performance standard for Category 1 to 3 applications while maintaining the 80 percent standard for Category 4 and 5 applications. Further, the new performance standards establish specific decision writing timelines for categories 1 to 5, which are 15, 20, 30, 75 and 90 days, respectively.

TransCanada Energy Ltd. Application Requesting Release from Direction in Decision 23349-D01-2018 (AUC Decision 24826-D01-2019)

Release from Direction

In this decision, the AUC released TransCanada Energy Ltd. ("TC") from the AUC's direction in *Decision 23394-D01-2018*. This direction required TC to advise the AUC if Express Pipeline Ltd. ("Express") ceased to receive electricity services from the Wildhorse Line.

Background

On April 30, 1998, the AUC predecessor, the Alberta Energy and Utilities Board issued Order U98075. This Order granted TC's application for the Wildhorse Line to be exempt from the definition of "electric utility".

On August 22, 2019, TC and Express filed a joint letter with the AUC informing the AUC of their asset purchase and sale agreement. In the asset purchase and sale agreement, TC agreed to sell its 69-kilovolt electric power transmission line, the Wildhorse Line, to Express.

Commission Findings

The AUC recognized that following the sale of the Wildhorse Line, TC will no longer be the owner of the facilities subject to Order U98075 and will have no knowledge of whether Express is receiving electricity services from the Wildhorse Line. Therefore, the AUC released TC from the AUC's direction in *Decision 233094-D01-2018*.

CANADA ENERGY REGULATOR

AltaGas Holdings Inc. Application for Approval to Abandon the Acadia Valley Pipeline and Acadia Valley Tie-ins (CER Decision MHW-007-2019)

Gas - Pipeline Abandonment

This is a decision by the National Energy Board ("NEB"), released on the letterhead of the CER.

In this decision, the NEB considered an application the ("Application") from AltaGas Holdings Inc. ("AltaGas") for leave to abandon its 7.7 kilometre natural gas Acadia Valley Pipeline (the "Pipeline" or "Project") and tie-ins. Pursuant to section 74 of the *National Energy Board Act* and section 50 of the *National Energy Board Onshore Pipeline Regulations*, the NEB granted AltaGas leave to abandon the pipeline subject to conditions set out in Order ZO-A174-007-2019.

<u>Assessment of the Application</u>

Engineering Matters

The NEB was content with the abandonment activities described in the Application. The NEB found AltaGas abided by its commitment and requirement to comply with *Canadian Standards Association Standard Z662-15: Oil and Gas Pipeline Systems* and *NEB Onshore Pipeline Regulations.* AltaGas was further reminded of its obligations to comply with the new edition of *CSA Z662-19.*

Economic Matters

The NEB was of the view that the abandonment would not have a material impact on tolls or shippers as the facilities had no current customers. AltaGas submitted that the estimated total cost of the abandonment would be $131,791 and confirmed that funding would be available for the proposed abandonment and post-abandonment monitoring and contingency.

The NEB imposed *Condition 4 - Quarterly Physical Abandonment Activity Cost Reports* which required AltaGas to provide cost data broken down by abandonment activity. The NEB imposed this condition to work towards improving the accuracy of abandonment cost estimates.

Environment Matters

The NEB was of the view that abandoning the pipeline in place posed low environmental risk.

No historical spills, odours or surface staining were identified as a result of the assessment. AltaGas' Environmental Protection Plan ("EPP") included mitigation measures to be implemented in the event contamination is encountered or suspected during abandonment activities, as well as measures for spill prevention, preparedness and management.

Condition 5 - Reclamation Reporting was imposed by the NEB. This condition set out the requirements and schedule for reporting progress to the NEB for addressing the environmental issues and the equivalent land capability objective. AltaGas is required to monitor the Pipeline Right of Way ("RoW") and provide Reclamation Reports following the completion of abandonment activities. These Reports need to demonstrate that the RoW had reached or would reach equivalent land capability.

Considering the conditions and circumstances of the abandonment, the NEB anticipated any potential adverse environmental effects arising from the Project would not be likely to cause any significant adverse environmental effects.

Public Consultation, Lands and Socio-Economic Matters

The NEB was satisfied that anyone potentially affected by the Project was informed of the Project, given notice and had the opportunity to bring concerns to AltaGas or the NEB. The NEB viewed the consultation activities to have been appropriate for the scale and scope of the Project.

Indigenous Matters

The NEB found that Indigenous communities potentially impacted by the abandonment activities were sufficiently notified. These communities also had further opportunities to voice any concerns.

<u>Decision</u>

The NEB granted AltaGas leave to abandon the facilities.

NOVA Gas Transmission Ltd. Application for Approval of Amendments to the NGTL Gas Transportation Tariff Temporary Service Protocol (CER Decision RH-002-2019)

Gas - Transportation Tariff - Temporary Service Protocol

In this decision, the CER considered an application (the "Application") by NOVA Gas Transmission Ltd. ("NGTL") with the CER's predecessor, the National Energy Board ("NEB"), for amendments to the NGTL tariff to incorporate a Temporary Service Protocol. Under the Temporary Service Protocol, NGTL requested that IT-R and FT-R upstream of a constraint on the NGTL System be curtailed before IT-D or IT-S injections at East Gate, under certain system conditions. In simple terms, NGTL proposed that downstream throughput be sourced by giving priority to downstream supply, over upstream supply, under certain system conditions. The Temporary Service Protocol would achieve this by giving priority service to interruptible downstream gas supply services over firm and interruptible upstream gas supply services.

The CER approved the Application as filed and ordered that tolls may be charged in accordance with the amended tariff, effective September 30, 2019. The CER stated that its reasons for the decision would follow. The CER indicated it released the decision in advance of the reasons in response to the requests from NGTL and other parties for an expedited decision.

Enbridge Pipelines Inc. (Enbridge) Mainline Open Season (CER September 27, 2019 Letter Decision)

Oil - Open Season - Firm Transportation

In this decision, the CER considered submissions from Suncor Energy Inc. ("Suncor"), Shell Canada Limited ("Shell"), the Explorers and Producers Association of Canada ("EPAC"), and Canadian Natural Resources Limited ("CNRL") seeking relief regarding Enbridge Pipelines Inc.("Enbridge")'s ongoing open season process for firm service on its Mainline. The CER found Enbridge could not offer firm service to prospective shippers on the Mainline until such firm service has been approved by the CER.

<u>Background</u>

Between August 23 and 26, 2019, the National Energy Board ("NEB", the CER's predecessor) received four submissions regarding Enbridge's current open season for firm service on its Mainline. Suncor requested an order of the NEB declaring that Enbridge may not offer firm service on the Enbridge Mainline until such firm service is approved by the NEB and included in the Mainline tariff. Shell, EPAC, and CNRL each requested that the open season be extended or stayed until the NEB had reviewed certain aspects of the open season process or offering, or firm service on the Mainline in general.

<u>Views of the Commission</u>

The CER indicated it had concerns regarding the fairness of Enbridge's open season process and the perception of abuse of Enbridge's market power. The CER noted that Enbridge controls over 70 percent of oil transportation capacity out of the Western Canadian Sedimentary Basin. There is a lack of alternative transportation options for potential shippers. Therefore, the open season does not provide an accurate reflection of market support for Enbridge's firm service offering. Additionally, Enbridge had not indicated that it planned to use the open season to demonstrate the economic feasibility of new pipeline capacity.

The CER stated that potential shippers would benefit from a regulatory review of the terms and conditions of firm service on the Mainline before being required to make contracting decisions. This would provide more certainty and transparency to potential shippers, and would contribute to the efficient functioning of markets.

The CER found that it would not be in industry's best interest for the CER to dictate the terms and processes for open seasons, unless it was necessary in the circumstances. In the CER's view, intervention was necessary in the specific and unique circumstances of Enbridge's current open season, which are distinct from previous cases.

The CER granted the relief requested by Suncor. The CER ordered that Enbridge may not offer firm service to prospective shippers on the Mainline until such firm service, including all associated tolls and terms and conditions of service, has been approved by the CER. The CER noted that such an approach is consistent with the NEB's long-standing principles of transparency, fairness, and preventing abuse of market power.

Westcoast Energy Inc. Applications for Approval of T-South Reliability and Expansion Program (CER Decision GHW-002-2018)

Gas Pipeline - Upgrades and Expansion

This decision provides reasons of the National Energy Board ("NEB") under the letterhead of its successor, the CER.

In this decision the NEB considered applications filed by Westcoast Energy Inc. ("Westcoast") to construct and operate the following upgrades and an expansion to its pipeline system:

- the CS-4A Compressor Station Upgrade Project;
- the CS-5 Compressor Station Upgrade Project;
- the CS-3 Compressor Station Upgrade Project; and
- the T-South Expansion and Reliability Project,

(collectively, the "Projects").

<u>Statutory Framework</u>

In considering any application under Part III of the *NEB Act*, the NEB must consider whether the applied-for facilities are in the overall Canadian public interest. In doing so, the NEB must exercise its discretion in balancing the interests of a diverse public and requires that the NEB balance the benefits and the burdens of a project, in considering all relevant evidence properly before the Board.

<u>The Projects</u>

The Projects would take place at eight existing compressor stations along the Westcoast Transmission-South Pipeline System ("T-South pipeline") in British Columbia. The Projects would include the installation of five new compressor units and associated equipment at three existing compressor stations, and the completion of equipment upgrades to three other existing compressor stations on the T-South pipeline.

The Projects would be located entirely within Westcoast-owned fee simple lands, with the exception of CS-3. The CS-3 Project would require an additional 0.21 hectares of new lands on adjacent, privately-owned industrial land.

<u>Project Assessment</u>

Need for the Project and Economic Feasibility

The NEB found that Westcoast had demonstrated a need for the improved reliability provided by the Projects. The NEB also found that there was adequate supply, sufficient market demand, and robust contracts underpinning the Projects. Therefore, the NEB was of the view that the applied-for facilities were likely to be used and useful at a reasonable level over their economic life and were economically feasible.

Toll Principles and Methodology

The Board found the proposed tolling methodology, using rolled-in cost of service, to be appropriate for the circumstances of the Projects and that applying the proposed methodology would result in just and reasonable tolls. The rolled-in tolling methodology was consistent with Westcoast's existing practice for system expansions.

Facilities and Emergency Response Matters

The NEB found that the general design of the Projects facilities was appropriate for the intended use, and that the facilities would be constructed in accordance with accepted standards for design, construction and operation. The NEB also found that the general procedures and safeguards in place for the Projects were appropriate for its intended use. The NEB was satisfied that the Projects would be operated and maintained in a safe and appropriate manner.

Land Matters

The NEB found that Westcoast's anticipated requirements for land rights and the process for the acquisition of those land rights was acceptable and therefore, the NEB was satisfied that the acquisition would meet the requirements of the *NEB Act*.

Public Consultation

The NEB found that Westcoast's public consultation approach was adequate. Westcoast adequately and appropriately identified and notified stakeholders and potentially affected landowners. The NEB also noted that Westcoast's design and implementation of consultation activities for the Projects were appropriate given the scope and scale of the Projects.

Indigenous Matters

The NEB noted that Westcoast provided Indigenous communities who expressed an interest in the Projects with reasonable opportunities to participate in project planning, share traditional knowledge, and identify site-specific and general concerns about the Projects. Further, the NEB noted that Westcoast designed and implemented consultation activities that were appropriate for the size, scope and scale of the applied-for Projects.

The NEB found that consultation was meaningful, responsive and significant. Therefore there was adequate consultation and accommodation for the purpose of the NEB's decision on these Projects. The NEB also noted that, with the NEB's conditions, its regulatory requirements, along with company's mitigation and commitments, potential impacts of the Projects on the rights and interests of affected Indigenous peoples had been effectively addressed.

Environment and Socio-Economic Matters

The NEB found that, with the implementation of Westcoast's environmental protection procedures and mitigation and the NEB's imposed conditions, the Projects would not cause significant, adverse environmental or socio-economic effects.

Conclusion

The NEB approved the Projects subject to 20 conditions contained in four separate orders declaring each project to be in the public interest. The NEB indicated it would monitor and enforce compliance with the conditions throughout the lifecycle of the Projects.