REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

IN THIS ISSUE:

ALBERTA UTILITIES COMMISSION

Amendments to AUC Rule 027, AUC Bulletin 2020-32

Bulk-Power System Security - Critical Infrastructure Protection Reliability Standards

On October 21, 2020, the AUC amended Rule 027: *Specified Penalties for Contravention of Reliability Standards* with the addition of clause 5.3.

The previous version of Rule 027 required the Market Surveillance Administrator ("MSA") to publish every notice of specified penalty issued for contraventions of reliability standards, including those related to critical infrastructure protection ("CIP"). CIP reliability standards imposed certain physical and cybersecurity requirements on Alberta generating units. The rule also required the MSA to post whether penalties were paid or a notice of specified penalty was disputed and, in the latter case, to post a link to the resulting AUC decision relating to that dispute.

The Federal Energy Regulatory Commission ("FERC") released its *Joint Staff White Paper on Notices of Penalty Pertaining to Violations of Critical Infrastructure Protective Reliability Standards* ("White Paper"). The FERC and North American Electric Reliability Corporation ("NERC") jointly concluded, "there are substantial risks to the security of the Bulk-Power System resulting from the disclosure of CIP violator names and other information found in CIP noncompliance submissions." Consequently, the FERC would be keeping confidential all information related to the investigation and enforcement of contraventions of critical infrastructure protective reliability standards and NERC would no longer publicly post redacted versions of CIP noncompliance filings and submittals.

The AUC reviewed the findings and decided to adopt the joint FERC and NERC position regarding confidentiality. Rule 027 was revised to exempt the MSA from making public any notices of specified penalties related to contraventions of critical infrastructure protective reliability standards, including any related documentation. The AUC added clause 5.3:

> ***5 Posting of notice of specified penalty***
>
> […]
>
> 5.3 Subsections 5.1 and 5.2 shall not apply to a notice of specified penalty issued for a contravention of a critical infrastructure protection (CIP) reliability standard. A notice of specified penalty issued for a contravention of a CIP reliability standard and all associated information, including nonpayment or a dispute of the specified penalty or a Commission decision respecting the disputed specified penalty, will not be public.

Process Improvements to AUC Rate Proceedings, AUC Bulletin 2020-33

Rule 001 - Rule 022

The AUC announced it would make changes to its process and procedures for rate cases. The Bulletin provides additional information concerning the implementation of changes recommended in the report by the *AUC Procedures and Process Review Committee*.

The AUC accepted 29 of the 30 report recommendations. It did not accept one recommendation, that a legislated tightening of the AUC's decision-making timeframes is unnecessary. The AUC noted that legislation could be an effective option to focus the AUC and stakeholders on the AUC commitment to efficiency.

The AUC noted that while some of the recommendations may eventually require inclusion in Rule 001: *Rules of Practice,* to implement the efficiencies described in the committee's report, the AUC would adopt some recommendations immediately, as briefly outlined below:

- Assertive case management;

- Confidentiality;
- Hearings (presumption that rate setting hearings be conducted in writing);
- Cross-examination and Aids to Cross-examination (focus on reduction, limited to areas and issues, aids to cross strictly controlled);
- Non-expert opinion evidence (non-expert opinion evidence should be discouraged through reduction of costs);
- Rebuttable presumption - previous rulings;
- Argument (oral argument to be delivered within three business days of the close of hearing);
- Assertiveness in hearing room;
- Decisions (adopt template for decision writing that is issue-driven);
- Training for decision writing;
- Member training;
- Plenary meetings (formal recognition of benefits of plenary meetings to discuss generic issues that arise in proceedings);
- Interventions (AUC should hold parties to scoped issues, guard against repetitious evidence);
- Costs (AUC should recognize and apply extensive discretion it possesses to deny or reduce cost claims); and
- Rules review (review of Rule 001: *Rules of Practice*).

The recommendations accepted by the AUC will be examined with a view of incorporating them into the AUC Rule 001: *Rules of Practice* if necessary to effectively reduce regulatory lag and burden.

***Suspension of Specified Penalties Program for Certain Self-Reported Contraventions Extended to June 18, 2021,* AUC Bulletin 2020-34**
Bulletin

The AUC extended the operation of Bulletin 2020-10 until June 18, 2021, the date on which the repayment period concluded under the *Utility Payment Deferral Program Act.* The extension would promote the self-disclosure of contraventions while still allowing Alberta's electric and utilities, service providers and retailers to continue their focus on helping their customers during the ongoing COVID-19 crisis.

***AUC 2021 Generic Cost of Capital,* AUC Decision 24110-D01-2020**
Rates

In this decision, the AUC set the return on equity ("ROE") of 8.5 per cent and deemed equity ratio of 37 per cent (39 per cent for AltaGas Utilities Inc.) (collectively, the ROE and equity ratios, referred hereto as "Parameters") for the year 2021 on a final basis. The established Parameters will apply to the following utilities:

- AltaGas Utilities Inc. ("AltaGas");
- AltaLink Management Ltd. ("AltaLink");

- ATCO Electric Ltd. (“ATCO Utilities”);
- ATCO Gas & Pipelines Ltd.(“ATCO Utilities”);
- ENMAX Power Corporation (“ENMAX”);
- EPCOR Distribution & Transmission Inc. (“EPCOR”);
- FortisAlberta Inc. (“Fortis”);
- KainaiLink L.P.;
- City of Lethbridge;
- PiikaniLink L.P;
- The City of Red Deer; and
- TransAlta Corporation (“TransAlta”),

collectively, the “Alberta Utilities”.

The Parameters set out in this decision did not apply to EPCOR Energy Alberta GP Inc., ENMAX Energy Corporation, and Direct Energy Regulated Services because these utilities are regulated pursuant to the *Electric Utilities Act*, the *Regulated Rate Option Regulation,* and the *Gas Utilities Act Default Gas Supply Regulation*, respectively.

The parameters for the various investor-owned water utilities under the AUC’s jurisdiction were not determined in this proceeding. However, the determinations in this proceeding may be considered in other proceedings, should issues respecting ROE and deemed equity ratios arise for these utilities.

<u>Background</u>

On December 4, 2018 the AUC initiated the 2021 Generic Cost of Capital (“GCOC”) proceeding. Subsequent to evidence having been filed, the AUC suspended the proceeding for six months on March 19, 2020. In light of the extraordinary turmoil and uncertainty in financial markets at the time on account of the COVID-19 pandemic, the AUC advised that it would review and reassess its decision every 30 to 60 days, unless circumstances changed dramatically and called for earlier action.

The AUC’s last communication with registered parties in this proceeding was on August 7, 2020. The AUC acknowledged at that time that all parties, except for the Consumers’ Coalition of Alberta, maintained their positions that the ongoing COVID-19 pandemic and related economic and financial market uncertainty/volatility continued to preclude the immediate successful resumption of the proceeding. The Commission also acknowledged parties’ requests to update their evidentiary submissions upon the eventual resumption of the proceeding.

By way of a letter dated May 26, 2020, the AUC noted the Alberta Utilities’ request to extend into 2021 for each utility, on a final basis, the currently approved ROE of 8.5 per cent and equity ratio of 37 per cent (39 per cent for AltaGas) as originally approved in Decision 22570-D01-2018. This request from the Alberta Utilities was premised on the need to ensure stability for the utilities, customers, and investors given how little time remained for the AUC to conduct the proceeding and issue a prospective decision by the end of 2020.

The AUC wished to explore practical ways of addressing the concerns raised by the utilities, including, especially, the need for certainty and stability in the current environment, despite the unsettled nature of financial markets, by allowing for final parameters to be established in advance of the test period. The AUC offered each regulated utility the ability to select one of the following options for setting its Parameters in 2021:

(1) Fully interim Parameters for 2021.

(2) Rolling final retrospective Parameters for 2021.

(3) Rolling final prospective Parameters for 2021.

(4) Fully final Parameters for 2021 determined by way of a negotiated settlement with parties.

(5) Fully final Parameters for 2021 with an ROE of 8.3 per cent.

In the same correspondence, the AUC clarified that the deemed equity ratios would mirror the treatment of the ROE under each of options 1, 2 and 3 for 2021. Under options 4 and 5, the deemed equity ratios determined in the 2018-2020 GCOC will be effective for the duration of 2021.

In response, AltaGas, Fortis, EPCOR, AltaLink, the ATCO Utilities, and ENMAX elected Option 3 – Rolling final prospective parameters for 2021. While the City of Lethbridge and the City of Red Deer opted for Option 1, they noted that if other utilities unanimously selected an option, the cities should receive the same treatment, so Option 3 was extended to those parties. TransAlta did not file a statement of intent to participate and made no election.

In conformance with an earlier GCOC decision, the AUC was of the view that “early 2021” could be an appropriate time to return to the task of determining going-forward parameters for the utilities. The AUC considered that this timing was unlikely to permit a final decision to be issued prior to the end of the third quarter of 2021. This meant that those utilities that selected rolling final prospective parameters for 2021, from a list of five options, would receive their current ROE and equity thickness parameters for the entirety of 2021 on a final basis. The scope of the future GCOC proceeding would no longer include 2021.

The AUC concluded this proceeding without further process and will commence a new GCOC proceeding to address a future period. Parties seeking to rely on evidence filed in the current proceeding may refile this evidence in the new GCOC proceeding. The AUC also granted The City of Calgary’s request for leave to file evidence. Calgary was permitted to do so concurrently with other parties. The AUC would pre-register all registered parties in this proceeding in the upcoming new GCOC proceeding and provide additional process related details in the near future.

Decision

The AUC approved a generic ROE and equity ratio for AltaGas, AltaLink and its partners PiikaniLink L.P. and KainaiLink L.P., ATCO Utilities, ENMAX, EPCOR, Fortis, the transmission operations of the City of Lethbridge, the transmission operations of The City of Red Deer, and certain electricity transmission assets of TransAlta, as being set by extending the currently approved rate for the duration of 2021.

***Barlow Solar Park,* AUC Decision 25690-D01-2020**

Facilities, Solar Power Plant

In this decision, the AUC approved an application from Barlow Solar Park Ltd. (“Barlow Solar”) to construct and operate a 27-megawatt solar power plant in the City of Calgary, and to connect the power plant to the Alberta Interconnected Electrical System (collectively, the “Project”).

Discussion

The Project will be located on previously disturbed land within the City of Calgary, and will consist of approximately 100,000 solar panels grouped into approximately 1,500 rack-mounted fixed-tilt solar panel tables, 10 inverters, five transformer stations with medium voltage step-up transformers, a collector system, an on-site electrical building, an access road, a small area for construction or temporary laydown and storage, and a perimeter fence. The power plant will have a gross generation capability of 17 megawatts.

ENMAX Power Corporation ("ENMAX") confirmed its willingness to connect the power plan to ENMAX's 25-kilovolt electric distribution system provided that Barlow Solar demonstrates compliance with applicable rules, standards and ENMAX's interconnection requirements.

Findings

The AUC was satisfied that the technical, siting, emissions, environmental, and noise aspects of the Project met the AUC's requirements. The AUC was satisfied that Barlow Solar conducted its participant involvement program in accordance with Rule 007.

The AUC noted that Alberta Energy and Parks ("AEP") did not prepare a renewable energy referral report for this Project, given that the *Wildlife Directive for Alberta Solar Energy Projects* does not apply to projects in urban areas. The AEP project review letter stated that AEP supports the siting and development of solar projects within urban areas. This is because urban solar projects have limited impact to wildlife and wildlife habitat, have reduced requirements for transmission infrastructure, and reduce development pressure in locations with higher quality wildlife habitat.

The AUC was satisfied that with diligent implementation of the mitigation measures outlined in the environmental evaluation and adherence to commitments made by Barlow Solar, the identified environmental effects of the Project could be mitigated to an acceptable degree.

Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants* applies to all solar projects approved after September 1, 2019. Accordingly, Barlow Solar must comply with the requirements of Rule 033. In accordance with Rule 033, as a condition of the approval, the AUC directed Barlow Solar to submit an annual post construction monitoring survey report to AEP and the AUC within 13 months of the Project becoming operational, and on or before the same date every subsequent year for which AEP requires surveys pursuant to subsection 3(3) of Rule 033.

The AUC noted that the glare analysis stated there are buildings between the solar park and Deerfoot Trail S.E. and that the solar park would be surrounded by a perimeter fence at an elevation higher than vehicles travelling on Deerfoot Trail S.E., which would decrease the amount of solar glare drivers could receive to a negligible amount. However, the AUC wanted to ensure that any deleterious glare associated with the Project is addressed by Barlow Solar in a timely manner. Accordingly, as conditions of approval, the AUC required that Barlow Solar use an anti-reflective coating on the Project's solar panels. The AUC further directed Barlow Solar to file a report detailing any complaints or concerns it receives or is made aware of regarding solar glare from the Project during its first year of operation, as well as Barlow Solar's response to the complaint.

Barlow Solar had not yet finalized its selection of inverters and panels for this Project, nor finalized the Project's layout. The AUC therefore directed Barlow Solar, as a condition of approval, to file a letter with the AUC that identifies the make, model, and quantity of the equipment and, if the equipment layout had changed, and an updated site plan. This letter should confirm that the finalized design of the Project will not increase the land, noise and environmental impacts from what was approved by the AUC for the base reference case. The letter must be filed no later than one month before the scheduled commencement of construction.

The AUC approved the Barlow Solar Park power plant application and the interconnection application subject to the noted conditions.

Alberta PowerLine Limited Partnership Application for Exemption from Rule 005, AUC Decision 25477-D01-2020
Exemption from ISO Reporting Requirements

In this decision, the AUC approved the application from Alberta PowerLine Limited Partnership ("APL") requesting an exemption from the reporting requirements of Rule 005: *Annual Reporting Requirements of Financial and Operational Results*. In its application, APL further requested that the exemption be approved for the duration of APL's contractual obligation to operate the Fort McMurray West transmission facilities, which is expected to terminate on June 27, 2054.

Background

APL was an electric "utility established specifically to develop the Fort McMurray West 500 kilovolt ("kV") transmission project." Section 4 of the schedule "Critical Transmission Infrastructure" in the *Electric Utilities Act ("EUA")*identified two single-circuit 500 kV alternating current transmission facilities from the Edmonton region to the Fort McMurray region as critical transmission infrastructure. Critical transmission infrastructure is subject to Part 2.1 of the *Electric Utilities Act* ("*EUA*").

Section 24.2 of the *Transmission Regulation* specified that the Fort McMurray project, as critical transmission infrastructure, must be procured by a competitive process developed by the Independent System Operator, and the AUC must approve the process. The Independent System Operator in Alberta operated as the Alberta Electric System Operator ("AESO"). The AUC approved the competitive process, to be conducted by the AESO, for the Edmonton Fort McMurray transmission lines.

In Decision 23161-D01-2018, the AUC found that the contractual agreement between the AESO and APL ("Project Agreement") related to certain transmission assets for the Fort McMurray West Transmission Project was prudent, as required by section 24.2(4) of the *Transmission Regulation*. The Project Agreement sets out the monthly payments from the AESO to ALP over the Project Agreement's operating period.

In the current application, ALP confirmed that the Project Agreement defines the payments made to ALP by the AESO for the use of the facilities, and the agreement is expected to terminate on June 27, 2054.

Findings

Section 8(2) of the *Alberta Utilities Commission Act* enables the AUC to act on its own initiative or motion and do all things that are necessary for or incidental to the exercise of its powers and the performance of its duties and functions. Section 8(5)(b) specifies the AUC may make an order granting the relief applied for. The AUC found that ALP's request for an exemption from Rule 005 falls within the AUC's discretionary authority. The AUC considered that a partial or full exemption should only be granted in limited circumstances.

As an owner of an electric utility, as per sections 1(jj) and 1(o) of the *EUA*, ALP has a duty to maintain accounts and records under section 118(1) of the *EUA*. Rule 005 annual filings, the manner in which the AUC gathers reports of electric utilities' financial and operational information, has been created under the AUC's rule-making authority under section 118(2) of the *EUA*.

ALP relied on the terms of the Project Agreement and its inability to report information to the extent required by Rule 005 as reasons why the exemption should be granted. The AUC determined that this characteristic does constitute a compelling justification for granting an exemption to ALP from filing under Rule 005.

The utility's revenues arose out of a legislatively sanctioned competitive process approved by the AUC and resulted in a Project Agreement between the utility and the AESO, which determined ALP's revenues received over the life of the agreement. ALP's general tariff application was approved in Decision 23161-D01-2018 based on the terms of the Project Agreement, including the expected termination date of the agreement in 2054.

The AUC noted that the payments required by the Project Agreement are ultimately included in the AESO tariff as part of the AESO's total administrative costs. The AESO's administrative costs are subject to the oversight of the AESO's board and the AUC's review of these costs is limited.

The AUC also made note of certain changes in the Project Agreement and prices which are addressed through the adjustment methodologies that were approved by the AUC in Decision 2013-044. These are subject to a materiality threshold and other conditions. If a change is allowed for by the terms of the Project Agreement such as the payment, schedule and other obligations, section 24.3 of the *Transmission Regulation* allows for the AESO and ALP to change the agreement. Section 24.3(3) of the *Transmission Regulation* states that "The Commission's approval must be obtained before the ISO and the eligible person make a change if in the opinion of the ISO (a) a material change to the resulting arrangement is required, and (b) the change may not be made under the terms of a resulting arrangement." In the event of a dispute between the AESO and APL regarding a change, either party can submit the dispute to the AUC for its determination, under section 24.3(4) of the *Transmission Regulation*. Because of these provisions, the AUC noted that it will have oversight over changes or disputes pursuant to sections 24.3(3) and 24.3(4) tof the *Transmission Regulation* that will allow the AUC to compel information to resolve the dispute and annual Rule 005 reporting is unnecessary in the circumstances.

While transparency of utilities' financial and operational information is generally a benefit of Rule 005, the AUC found that the transparency of ALP achieved through this reporting would be limited. Rule 005 reporting as a tool for comparison to other electric utilities would also be relatively limited because ALP's revenues are not recorded through a traditional rate base rate-of-return methodology, operating and maintenance costs are not classified by comparable expense categories, and only a subset of Rule 005 information and schedules can be reported.

The AUC granted the exemption from the annual reporting requirements of Rule 005, as filed. The exemption would apply until the agreement terminates in 2054. Further, the AUC confirmed that the approved exemption applies to the 2019 Rule 005 reporting requirements. The AUC noted that the granting of this exemption did not relieve ALP from its duty to maintain accounts and records in accordance with section 118(1)(a) of the *EUA*. The AUC further noted that this decision does not preclude or limit the AUC's authority under section 118(1)(b) of the *EUA* to require the disclosure of financial or operational information in future proceedings.

AltaLink Management Red Deer Area Transmission Development Decommission and Salvage of Remaining Portions of Transmission Lines 80L and 716L, **AUC Decision 25140-D01-2020**

AUC Jurisdiction - Historical Resources

In this decision, the AUC approved applications from AltaLink Management Ltd. ("AltaLink") to decommission and salvage portions of transmission lines 80L and 716L.

Applications

AltaLink filed applications with the AUC for approval to salvage approximately 24 kilometers of 138-kilvolt ("kV") Transmission Line 80L and approximately 36 kilometers of 138-kV Transmission Line 716L, as well as to salvage one 138-kV circuit breaker, and its associated components, from the Wetaskiwin 40S Substation. AltaLink also applied on behalf of TransAlta to salvage the portions of Transmission Line 716L located within I.R. 137 and I.R. 138.

AltaLink explained that the Alberta Electric System Operator ("AESO") had determined that portions of transmission lines 80L and 716L would no longer be required following the completion of facilities described in the Red Deer Area Transmission Development. The AUC approved the needs identification document for the Red Deer Area Transmission Development, which included the discontinuance of transmission lines 80L and 716L, on April 10, 2012.

AltaLink stated that it was directed by Alberta Culture and Tourism to consult with 15 First Nations whose membership could include descendants from the disbanded Sharphead Reserve. It provided detailed information about its consultation with those First Nations, and it summarized their requests in relation to the Sharphead Burial Site.

Sharphead Burial Site

In its application, AltaLink identified that one structure to be salvaged was located within a site with significant historical and cultural importance. AltaLink stated that the Sharphead Burial Site, which is located on private land, was under the direction of Alberta Culture, Multiculturalism and Status of Women ("ACMSW"), pursuant to its authority under the *Historical Resources Act*. AltaLink indicated that the site was believed to contain one or more human remains beneath Structure 827, and it had been designated Historical Resources Value Level 4.

AltaLink stated that it applied for and received *Historical Resources Act ("HRA")* approval from ACMSW for the portion of the project in the vicinity of the Sharphead Burial Site. The salvage method proposed by AltaLink for Structure 827, and approved by ACMSW, is different from how AltaLink proposed to salvage other structures along the transmission lines to allow for the removal of the structure in a manner that would cause as little disturbance as possible to any potential human remains or archeological materials.

Findings

The AUC determined that the technical and environmental aspects of the project met the AUC requirements. The AUC also found that the applications were consistent with the need previously identified by the AESO.

The AUC found that, other than issues related to the Sharphead Burial Site and Structure 827 and issues raised by the Matejaks in relation to how AltaLink conducted its participant involvement program, respectively, there were no outstanding technical or environmental concerns specific to the decommission and salvage of the lines or substation, nor were there any outstanding public or industry concerns.

Sharphead Burial Site and Structure 827

The AUC found that, concerning the Sharphead Burial Site, AltaLink, the Matejkas (the owners of the lands) and the First Nations who were consulted agreed that any human remains underlying Structure 827 must not be disturbed, and the site itself was to be protected and respected. Subject to that primary consideration, Transmission Line 80L should be salvaged and ultimately the lands should be reclaimed.

The matters upon which the Matejkas and AltaLink did not agree concerned how to affect both outcomes, with the Matejkas seeking compensation and additional measures and relief in terms of monitoring the site and subdividing the land.

In this unique situation, the AUC noted that its discretion in the matter is limited by the authority granted to and exercised by the ACMSW under the *HRA.*

Each of AltaLink and the Matejkas had filed separate *HRA* applications with ACMSW. ACMSW had issued separate approvals with conditions specific to the activities proposed to be undertaken by each of AltaLink and the Matejkas. As pointed out by AltaLink, the Matejkas were asking the AUC to impose conditions on AltaLink's *HRA* approval that duplicate those issued to the Matejkas for agricultural operations, despite the fact that AltaLink had its own *HRA* approval with conditions relating to decommissioning and salvage operations at the site.

The AUC acknowledged ACMSW's authority in relation to the historic resources that were present at the Sharphead Burial Site, and approved the salvage method stipulated in Approval HRA-4490-17-0002-0005 issued to AltaLink. The AUC noted it would not impose alternative or additional requirements related to the protection of the historic resources; doing so would be outside of the AUC's jurisdiction and constitute an unwarranted intrusion on ACMSW's expertise and authority. The AUC further noted it did not have the authority to order that compensation be paid to the Matejkas for the loss of use of the Sharphead Burial Site or for the Matejkas' time and effort spent attempting to resolve their concerns. The AUC advised it did not have the authority to order the subdivision of the land, or to require that a site management plan to preserve the historic resource be created or that its execution be funded by AltaLink.

Because AltaLink was required to apply for a reclamation certificate from Alberta Environment and Parks once the site has been reclaimed, the AUC found it preferable to leave any decisions about post-reclamation site monitoring to that authority.

While the Matejkas' desire to protect the site and the manner they proposed to manage it over the long term appeared to be well-considered, the AUC noted that its role in relation to the historic resources at the Sharphead Burial Site and its authority in this proceeding does not extend to making the orders sought by the Matejkas. The AUC nevertheless encouraged all of the parties, including the interested First Nations, to continue efforts to find a suitable long term solution that protects the site and addresses the Matejkas' concerns.

Participant Involvement Program

The AUC was concerned about the Matejkas' assertion that AltaLink did not conduct its consultation in good faith. The AUC recognized how, for example, AltaLink's decision to leave unconstructed poles on the Matejkas' land for the past 13 years may have impacted the Matejkas' relationship with AltaLink. Nonetheless, the AUC found that AltaLink's participant involvement program met its purposes of consultation. Accordingly, the AUC found that the participant involvement program undertaken by AltaLink met the requirements of Rule 007. The AUC expected AltaLink to honour any commitments it may have made to First Nations during the consultation process that were directed by ACMSW.

The AUC found the approval of the application to be in the public interest.

***Dow Chemical Canada ULC, TransAlta Cogeneration Ltd. and Prairie Boys Capital Corporation - Dow Fort Saskatchewan Industrial Complex Industrial System Designation and Ownership Transfer,* AUC Decision 25696-D01-2020**

Industrial System Designation

In this decision, the AUC approved an application from Dow Chemical Canada ULC ("Dow") for an industrial system designation ("ISD") that encompasses all facilities at the Dow Fort Saskatchewan Industrial Complex. The AUC further issued updated approvals, licences and orders for existing electric facilities at the Dow Fort Saskatchewan Industrial Complex to reflect transfers of ownership.

<u>ISD Application</u>

The AUC considered the ISD application in accordance with the principles and criteria set out in Section 4 of the *Hydro and Electric Energy Act* (*"HEEA"*).

The AUC noted that the industrial complex was previously the subject of an Alberta Energy and Utilities Board ("EUB") proceeding to address the credible threat that Dow would bypass the Alberta Interconnected Electrical System ("AIES") and construct duplicate transmission facilities, resulting in the approval of Rider A1. Rider A1 is a transmission bypass avoidance rate rider approved by the EUB in response to the threat that Dow would physically bypass the transmission system serving the industrial complex. Rider A1 was set to expire in 2021, and the AESO applied separately for an extension to Rider A1 that was contingent upon the outcome of the ISD application.

While the AUC considered the AESO's application for an extension to Rider A1 independently of Dow's ISD application, it found the historical and future rate treatment of the industrial complex relevant to its consideration of the ISD application.

As required by subsection 4(2)(c)(i) of *HEEA,* the AUC considered the principle that an ISD must not facilitate the development of independent electric systems that attempt to avoid costs associated with the AIES. In Decision U98125, the EUB addressed Dow's interest in constructing duplicate facilities to serve the industrial complex and determined that such a bypass would be physically, technically and economically viable. The AUC found that, despite Dow's previously documented interest in constructing bypass facilities, the principle driver of the ISD application was to enable the continued cogeneration of steam and electricity to meet the needs of its industrial processes and the export of excess electricity to the AIES.

The AUC found that granting the ISD was consistent with the principles in subsection 4(2)(c).

The AUC was also satisfied that subsections 4(3)(a) and 4(3)(b) of *HEEA* were met. The industrial complex's electric system included integrated cogeneration facilities that produce steam and electricity to serve the complex's industrial operations. Dow filed process diagrams demonstrating the integration between the various components of the industrial operations which culminates in the production of marketable products from feedstocks of natural gas liquids and ethane.

However, the AUC found subsection 4(3)(c) of *HEEA* had not been met, because there was not common ownership of all components of the industrial operations. The AUC further found that subsection 4(3)(d) had not been met, as Dow had not adequately explained how the whole of the output of each component within the industrial operation is used and is necessary to constitute its final products.

While the AUC found that subsections 4(3)(c) and 4(3)(d) of *HEEA* had not been met, it considered subsection 4(4), which authorizes the AUC to designate an industrial system if it is satisfied that all of the separately owned components and all of the industrial operations are components of an integrated industrial process. The AUC had previously found that operations with multiple owners would bear a greater burden to demonstrate that the assets are components of an integrated industrial process.

Submissions by Dow demonstrated that the cogeneration facilities, the industrial processes within the industrial complex, the cavern storage facilities and the Praxair air separation plant have integrated operations. In light of this integration, the AUC found that all the separately owned components and all the industrial operations are components of integrated industrial processes.

The AUC was satisfied that all the separately owned components of the proposed industrial system, and all of the industrial operations within the industrial complex are sufficiently integrated to meet subsection 4(4). The AUC approved the ISD application.

<u>Ownership Transfer Application</u>

When this proceeding was initiated, the approvals for the electrical facilities within the industrial complex and their respective connection orders each contained approval holder names that were no longer current.

Dow confirmed that neither it nor other parties had concerns with the AUC updating the existing approvals to reflect the current approval holder names. Dow also provided details of the ownership structures and confirmation that they are eligible to hold approvals und the *HEEA.*

The AUC reviewed the information provided by Dow, TransAlta Cogeneration Ltd., and Prairie Boys Capital Corporation and found no outstanding objections or concerns associated with the ownership transfers. The AUC considered the applications to be in the public interest in accordance with Section 17 of the *Alberta Utilities Commission Act.*

ENMAX Power 2021 Interim Transmission Facility Owner Tariff, **AUC Decision 25945-D01-2020**

Rates- Intergenerational Equity

In this decision, the AUC approved the application filed by ENMAX Power Corporation ("EPC") for its 2021 interim transmission facility owner ("TFO") tariff, effective January 1, 2021. The AUC approved the interim TFO tariff in the amount of $105.15 million. The 2021 interim TFO tariff would be collected by way of a monthly rate of $8.76 million.

Application

EPC's 2019 tariff of $96.59 million was approved by the AUC. EPC had filed for its 2021-2022 transmission general tariff (”GTA”), requesting a forecast 2021 revenue requirement of $110.86 million, but did not expect a decision to be given until the third quarter of 2021. EPC noted that with the continuation of the existing 2019 TFO tariff throughout 2021, a revenue shortfall of $14.27 million would occur.

To collect the 2021 interim tariff, EPC proposed to collect a monthly tariff of $8.76 million, effective January 1, 2021.

With regards to quantum and need factors, EPC submitted that the potential transmission revenue shortfall of $14.27 million was both probable and material, and if left unaddressed would cause financial hardship to EPC due to increased borrowing and decreased cash flow. Further, collecting only 60 per cent of the forecast increase related to the 2021 forecast revenue requirement would, in EPC's submission, adequately account for any potentially contentious or settled elements of the 2021-2022 GTA.

With respect to various public interest factors, EPC submitted that the 2021 interim tariff would promote rate stability and ease the effect of rate shock by reducing the increase that would otherwise result from the future implementation of a final 2021 tariff, decrease the quantum of an eventual true-up and provide for a more gradual and stable transition of its transmission tariff. Further, if a 2021 interim tariff was not approved, in EPC's submission, intergenerational equity could not be maintained because there is a substantial risk that customers' rates for the test period would not reflect the costs associated with that period. EPC asserted that while carrying costs could mitigate the financial hardship on EPC resulting from the revenue shortfall, carrying costs could not address the issues of rate shock or rate stabilization. EPC further noted that such carrying costs could compound the intergenerational inequity by increasing the amounts that must be recovered in future tariffs.

Findings

The AUC accepted EPC's submission that by collecting 60 per cent of the identified revenue shortfall, EPC would avoid the need for increased borrowing, and would therefore avoid financial hardship because of the material revenue shortfall between its existing 2020 tariff of $96.59 million and its forecast 2021 revenue requirement of $110.86 million.

As final rates for EPC are not likely to be in place before the fourth quarter of 2021, the AUC found the need for an interim adjustment to have been demonstrated.

The AUC found the public interest factors to be satisfied. The AUC agreed that the collection of a portion of any rate increase resulting from EPC's final 2021 tariff, would promote rate stability through a gradual rate increase. The AUC also agreed that the interim adjustment would help to maintain intergenerational equity and provide appropriate price signals to customers.

The AUC found that, while carrying costs would address part of the impact of the proposed revenue shortfall on EPC, carrying costs would not address the issue of rate stability, ease any potential rate shock, provide appropriate price signals to customers or address concerns for intergenerational equity.

The AUC approved EPC's requested 2021 interim TFO tariff as filed, to be effective January 1, 2021.

***ATCO Gas and Pipelines Ltd. 2020 Unaccounted-for Gas Rider D,* AUC Decision 25798-D01-2020**
Rates

In this decision, the AUC approved the application from ATCO Gas (“ATCO”), a division of ATCO Gas and Pipelines Ltd. for an unaccounted-for gas (“UFG”) Rider D rate of 1.102 per cent, effective November 1, 2020. The AUC also approved ATCO's request to include the Government of Canada carbon levy associated with line heater fuel use in its load-balancing deferral account (“LBDA”), but denied the request that other future carbon or climate change-related fees associated with line heater fuel be approved for collection through the LBDA. The AUC also denied ATCO's request for a no-notice process for future Rider D applications.

Background

Charges for UFG are recovered in-kind from all shippers on the ATCO Gas distribution system, including the default supply providers by way of a Rider D. The AUC noted that upon approval of ATCO Gas's proposed Rider D of 1.102 per cent, all customers of retailer and default supply providers utilizing distribution access service for delivering gas off the ATCO Gas distribution system will be assessed a distribution UFG charge of 1.102 per cent at the point of delivery. The effect is that all retailer and default supply provider customers must buy an extra 1.102 per cent of natural gas in order to zero-balance their receipts and deliveries on the ATCO Gas system.

Issues

Calculation of Rate Rider D

Consistent with previous Rider D applications, ATCO Gas calculated its Rider D rate using measurement data from the preceding three years, in this case from January 2017 to December 2019. ATCO Gas then averaged the UFG percentages for 2017, 2018, and 2019 to determine the Rider D rate for 2020.

Compliance with AUC Directions from Decision 24815-D01-2019

ATCO explained that the seasonal differences in UFG were a result of ATCO having over 1.2 million delivery points, of which the majority were read on monthly cycles. The Daily Forecasting and Settlement System ("DFSS") allocates monthly meter readings to daily flow using daily average temperatures and other factors such as season and day of the week. The calendarized monthly deliveries reported are calculated estimates and affect the accuracy of UFG on a month to month basis in the shoulder and summer months.

ATCO further attributed the seasonal differences in UFG to the fact that ATCO designs and builds the distribution system for peak operating conditions. During the shoulder and summer months, the operation of the distribution system needs to be adjusted to ensure accurate measurement during low-flow conditions. The appropriate timing of these adjustments is weather dependent since local temperature fluctuations are unpredictable

With respect to the direction regarding clear explanation of seasonal differences, measurement corrections or differences in UFG, ATCO identified the following issues that could cause UFG to increase or decrease:

Source	**Issue/concern**
Seasonal operating plans	The timing of when the seasonal operating plan can be implemented is dependent on the weather. In the shoulder month of spring and fall, temperatures can vary significantly and may affect UFG due to timing of the implementation of the seasonal operating plan.
Equipment failure	Event in which any part of the equipment does not perform according to its operational specifications.
Construction	Mixing of heat areas during construction. Purging and filling of pipelines.
Pipeline leaks and Hit lines	Gas lost to atmosphere.
Unsolicited use	Gas lost to theft.
Line heater fuel	Gas used during distribution system delivery.

In response to the direction to provide information on what steps had been taken to reduce UFG, ATCO noted it took various steps to minimize the UFG amount. This included implementing procedures to ensure measurement accuracy in the expected flow conditions.

The AUC lastly directed ATCO to provide details with respect to all measurement adjustments showing the reconciliation of prior years' data. In response, ATCO Gas and ATCO Pipelines are upgrading measurement equipment, data monitoring, verification of measurement data, seasonal operational adjustments, adjusting sample points and heat areas, as necessary.

ATCO stated that the 2019 UFG of 1.267 per cent was in line with comparable prior year fluctuations including 1.211 per cent for 2018 and 1.368 per cent for 2013.

Government of Canada Carbon Levy

In this application, ATCO proposed that the Government of Canada carbon levy associated with line heaters be collected through the LBDA. ATCO was directed to pay a carbon levy of $1.567 per gigajoule ("GJ") on fuel that is combusted in Alberta during the delivery of natural gas to customers. The Government of Canada carbon levy replaces the previous Government of Alberta levy, and ATCO considered it to be a like-for-like replacement. Therefore ATCO requested the same recovery mechanism for the Government of Canada carbon levy on line heater fuel through the LBDA. ATCO estimated the cost of the Government of Canada carbon levy on line heaters in 2020 to be approximately $425,000.

<u>Findings</u>

The AUC approved Rider D at 1.102 per cent and the Rider D Schedule, effective November 1, 2020. The AUC recognized that UFG is an element of operating a natural gas distribution system and accepted the reasons cited by ATCO for increases and decreases in UFG.

Regarding directions from Decision 24815-D01-2019, the AUC found ATCO to have complied with the directions given. ATCO was directed to continue to provide clear explanations for seasonal UFG differences, measurement corrections, and reasons for UFG increases or decreases. The AUC further directed ATCO to continue providing information on practices and procedures it had employed to reduce UFG.

Consistent with the Government of Alberta carbon levy treatment approved in Decision 22889-D01-2017, the AUC approved ATCO's proposal for the same recovery mechanism for the Government of Canada carbon levy on line heater fuel through the LBDA.

The AUC directed ATCO, in its next Rider D application, to show the monthly line heater fuel usage, the associated carbon levy dollars, and the difference from the previous year.

The AUC denied ATCO's request for approval of the collection of other future carbon or climate change-related fees associated with line heater fuel through the LBDA, as the AUC did not find this necessary at the time and did not see the approval reducing the regulatory burden.

The AUC further did not grant ATCO's request that "all future carbon or climate change fees" be included in the LBDA without having the details of the program or its impacts on line heater fuel. In the case of additional carbon or climate change programs that would affect ATCO's line heater usage, the impact to the LBDA would be best addressed at the time any such program is implemented or enacted.

The AUC was not convinced that it would be appropriate for future Rider D rate updates to occur through a no-notice process as outlined in AUC Bulletin 2015-09. Given that UFG had been trending upward from 2017 to 2019, the AUC considered that UFG should be monitored in future UFG Rider D proceedings, that issues related to future UFG application could be contentious, and that some process could be required to test the evidence presented in those proceedings. The AUC denied ATCO's request for a no-notice process in its future UFG Rider D applications.

CANADA ENERGY REGULATOR

Trans Québec and Maritimes Pipeline Inc. Reinforcement and Asset Purchase Application, CER GH-001-2020

Pipelines, Asset Purchase, Construction and Operation

In this decision, the CER approved an application from Trans Québec and Maritimes Pipeline Inc. ("TQM") to purchase and operate the Sabrevois Assets owned by Énergir L.P ("Énergir"), as well as to construct and operate the Bromont Compressor Station and Saint-Basile Interconnect. The Sabrevois Assets, the Bromont Compressor Station and Saint-Basile Interconnect are collectively referred to as the "Project".

<u>The Reinforcement and Asset Purchase Application</u>

In its application, TQM requested that the National Energy Board (now CER):

- Grant leave to purchase the Sabrevois Assets from Énergir in accordance with the Sale Agreement;
- Issue a report recommending the issuance of a Certificate of Public Convenience ("Certificate") for the continued operation of the Sabrevois Assets;
- Authorize TQM to include the purchase price of the Sabrevois Assets plus adjustments in the TQM System rate base;
- Grant leave to open ("LTO") the Sabrevois Assets;
- authorize the construction and operation of and exempting TQM from the requirements of paragraph 30(1)(a), and sections 31 and 33 of the *NEB Act* in relation to the Bromont Compressor Station and the Saint-Basile Interconnect;
- Issue an order affirming that prudently incurred costs required to provide service on the Sabrevois Assets, the Bromont Compressor Station and the Saint-Basile Interconnect would be included in the determination of the TQM System revenue requirement, and that the tolls for services on the applied-for facilities would be calculated using the same methodology used to calculate tolls for services on the TQM System, as determined through CER order from time to time; and
- Grant such further and other relief as TQM may request or the CER considered appropriate.

<u>Background</u>

The Sabrevois Assets are located in the Sabrevois area of Québec and consist of:

- Approximately 64 km of the pipeline currently operated by Énergir ("Sabrevois Pipeline"), extending from Énergir's Sabrevois Delivery Station to Énergir's Shefford Station
- Seven laterals, approximately 11 km total in length
- The following facilities which are attached to and form part of the Sabrevois Asset Purchase:
    - Sabrevois Delivery Station
    - Launcher and receiver facilities
    - Valve sites

- The land rights associated with the Sabrevois Asset Purchase and other interests of Énergir necessary for TQM's ownership, operation and maintenance of the Sabrevois Assets.

The construction of the Bromont Compressor Station consists of the construction of a compressor station comprised of one electrical compressor unit and one gas compressor unit and related components (collectively referred to as the "Bromont Compressor Station"). The Saint-Basile Interconnect consists of approximately 20 m of NPS 12 pipe connecting the TQM System to a planned Énergir delivery station at Saint-Basile-le-Grand, Québec (collectively referred to as the "Saint-Basile Interconnect").

Recommendations and Decision

Leave to TQM to Purchase the Sabrevois Assets and Section 52 Certificate Requiring Governor in Council ("GIC") Approval to Continue Operation of the Sabrevois Assets

Subject to the issuance of a Certificate, the CER decided that it was in the public interest to grant TQM leave to purchase the Sabrevois Assets from Énergir pursuant to paragraph 74(1)(b) of the *NEB Act*.

The CER recommended that a Certificate be issued for the continued operation by TQM of the Sabrevois Assets. The CER found that the continued operation of the Sabrevois Assets was required for present and future convenience and necessity, in accordance with section 52 of the *NEB Act*.

Authorization Pursuant to Section 59 of the NEB Act Regarding the Sabrevois Assets

Subject to the issuance of a Certificate, the CER approved TQM's request to include the purchase price of the Sabrevois Assets plus adjustments as detailed in Schedule C of the Sale Agreement in the TQM System rate base at closing.

Leave to Open the Sabrevois Assets Pursuant to Section 47 of the NEB Act

The CER was satisfied that the Sabrevois Assets met the Canadian Energy Regulator *Onshore Pipeline Regulations* ("*OPR*") requirements, and that the facilities were fit for their designed service. The CER consequently granted leave to TQM to open these facilities pursuant to section 47 of the *NEB Act.*

Order Pursuant to Section 58 of the NEB Act for the Bromont Compressor Station and the Saint-Basile Interconnect

Subject to issuance of a Certificate, the CER decided to issue an order pursuant to section 58 of the *NEB Act,* exempting TQM from the requirements of paragraph 30(1)(a), and sections 31 and 33 of the *NEB Act* for the Bromont Compressor Station and the Saint-Basile Interconnect.

Order Pursuant to Part IV of NEB Act

Should a Certificate be issued for the Sabrevois Asserts, the CER decided to grant the requested relief pursuant to Part IV of the *NEB Act*. Incurred costs required to provide service on the Sabrevois Assets, the Bromont Compressor Station and the Saint-Basile Interconnect will therefore be included in the determination of the TQM System revenue requirement, and the tolls for services on the applied-for facilities would be calculated using the same methodology used to calculate tolls for services on the TQM System.

Reasons for Decision

After setting out the CER's recommendations and decisions on the Project, the CER outlined the CER's reasons for decision. This included an examination of the public interest, as well as an analysis of the topics outlined below.

Economic and Financial Matters

The CER found the Project to be economically feasible and would likely be used at a reasonable level over its economic life. The CER found that TQM demonstrated a need for the Project and the Project was the least costly alternative that would allow TQM, Énergir, and TransCanada to meet existing contracts and position the pipelines to meet growing and shifting market demand from the abundant gas supply that TQM connects to through upstream pipelines. The CER had no concerns with TQM's ability to finance the purchase and construction, operation, and abandonment of the Project. The CER found TQM's proposal to roll the cost of the Project into TQM's rate base and to apply the existing TQM toll methodology to be reasonable.

Facilities and Emergency Response Matters

The CER was satisfied that the general design of the assets was appropriate for the intended use and that the assets would be operated in accordance with *Onshore Pipeline Regulation* ("*OPR*") and Canadian Standards Association ("CSA") standards.

The CER was satisfied that the Project will be constructed using accepted industry practices, and will comply with the requirements of the *OPR* and CSA Z662-19, with the exception of exemptions granted in the decision.

The CER found that the pressure control and overpressure protections proposed were appropriate and would meet the requirements of the *OPR* and CSA-Z662-19.

The CER was further satisfied that TQM considered issues related to coating and integrity threats and coating of the pipeline during construction and operation and implemented appropriate measures.

The CER noted that in line inspection ("ILI") could provide important data on the integrity status of the pipeline. The CER was of the view that ILI is a widely used pipeline industry best practice to monitor the condition of a pipeline and was satisfied with TQM's collected historical ILI data from Énergir for the Sabrevois Assets.

The CER understood that integrity monitoring is a continuous improvement process and conducted throughout the lifecycle of a project. The CER was satisfied that potential integrity threats would be identified and mitigated and that the Project would be incorporated into TransCanada's integrity management program once operations commence.

Emergency Management

While the CER was satisfied with TQM's commitment to continue refining the interoperability between the emergency management system it utilized, and the system used in the Province of Québec, the CER included Condition 7 in the Certificate in order to have TQM confirm that all agencies that may be involved in an emergency response on the Pipeline had been notified of the change of ownership.

Public Consultation

Regarding the Sabrevois Assets, the Bromont Compressor Station and the Saint-Basile Interconnect, the CER was of the view that TQM adequately and appropriately identified stakeholders and potentially affected landowners, and developed appropriate engagement materials. The CER was also of the view that TQM adequately designed and implemented engagement activities for the Project. The CER imposed Condition 8 to the Certificate to ensure TQM would update its signage to reflect the change in ownership.

Engagement of Indigenous Peoples

The CER was of the view that there was adequate consultation for the purpose of the CER's decision on this Project and that any potential Project impacts on the rights and interests of affected Indigenous peoples were not likely to be significant and could be effectively addressed. The CER found that the approval of this Project would be consistent with section 35 of the *Constitution Act, 1982* and the honour of the Crown.

Environment and Socio-Economic Matters

The CER concluded that the residual adverse environmental and socio-economic effects, including any residual cumulative effects, associated with the Project components would be of low magnitude, limited in extent, and therefore not significant.

BRITISH COLUMBIA COURT OF APPEAL

Coquitlam (City) v. British Columbia Utilities Commission, 2020 BCCA 289

Leave to Appeal - Decommissioning - Pipelines - Jurisdiction

In this decision, the City of Coquitlam ("City") obtained leave to appeal a reconsideration decision (the "Reconsideration Decision") of the British Columbia Utilities Commission ("BCUC"). The Reconsideration Decision affirmed an order authorizing FortisBC Energy Inc. ("Fortis") to abandon a decommissioned pipeline in place on City lands, and directing the parties to share removal costs equally in the event that the City requests the pipeline's removal to accommodate municipal infrastructure.

Leave was granted to consider what regulatory principles apply at the end of infrastructures' life in comparison to when it went into service, given the number of pipelines which are approaching the end of their usefulness.

<u>Background</u>

In 1955 the Public Utilities Commission of British Columbia approved by way of a "certificate of public convenience and necessity" ("CPCN") the construction of a Nominal Pipe Size 20 ("NPS 20") intermediate pressure gas line by the British Columbia Electric Company Ltd. ("BCEC"), 5.5 kilometres of which was to be located along Como Lake Avenue in the municipality of Coquitlam. In 1957 the company and the City concluded an operating agreement that required the company to obtain City approval before proceeding with new pipeline construction within its jurisdiction. The pipeline was built in 1958.

In 2015, the BCUC approved the construction of a new pipeline, the Lower Mainland Intermediate Pressure System Upgrade Projects ("LMIPSU Project"). The LMIPSU will pass through Coquitlam, Burnaby and Vancouver and will replace the NPS 20 pipeline with a larger line. A term of the approval provided that the NPS 20 pipeline would be permanently decommissioned.

As successor operator to the BCEC, Fortis entered into discussions with the City with respect to the new construction. Differences arose, however, over Fortis's proposal to abandon the NPS 20 pipeline in place. The City withheld its consent to the new construction unless Fortis agreed to two conditions:

> a) that Fortis, at its own cost, remove approximately 380 metres of the abandoned NPS 20 pipeline if the pipe ultimately conflicts with a planned City project that may proceed within 3 to 5 years, and patch the pavement to temporarily restore the road; and
>
> b) that Fortis agree to repave the entire width of Como Lake Avenue for 5.5 kilometres after completion of the LMIPSU Project, and to provide security in the form of a letter of credit in the amount of $6 million for all the paving work.

If realized, these two conditions would cost Fortis an estimated $5 million and $5.5 million respectively.

In 2018, Fortis applied to the BCUC for orders settling the terms of the new construction, pursuant to ss. 32 and 33 of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473 ("*UCA*"). Those sections make reference to situations where a public utility cannot come to an agreement with a municipality. The Court also made note of other sections of the *UCA*, including section 121 which insulates approvals from local government powers.

<u>BCUC Decisions</u>

On April 15, 2019 the BCUC made the following orders:

> 1. Pursuant to section 121 of the *UCA*, it is affirmed that Fortis is authorized to abandon the decommissioned NPS 20 pipeline in place.

2. Pursuant to section 32 of the *UCA*, upon request by the City in circumstances where it interferes with municipal infrastructure, the costs of removal of any portion of the decommissioned NPS 20 pipeline shall be shared equally between Fortis and the City.

3. The City's request that Fortis should be required to repair and repave the whole 5.5 kilometre section on Como Lake Avenue curb to curb is denied.

The City applied for reconsideration on two grounds: a) that the BCUC erred in finding it had jurisdiction to give "authorization" to Fortis within s. 121 of the *UCA* to abandon NPS 20 in place; and b) that the BCUC erred in finding that s. 32 of the *UCA* permitted it to specify the manner and terms by which the City could request Fortis to remove portions of NPS 20.

By order issued April 2, 2020, the BCUC dismissed the City's reconsideration application and invited further submissions from the parties respecting the process and evidentiary record of the "cost allocation formula" component of the Reconsideration Decision.

Noting that the *UCA* was silent on the BCUC's jurisdiction over decommissioned public utility assets, the tribunal cited *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board),* 2006 SCC 4 (S.C.C.) (hereinafter "*ATCO*") for the proposition that administrative tribunals may have powers that "exist by necessary implication from the wording of the act, its structure and its purpose." The BCUC found that the authority to authorize decommissioning arose by necessary implication from ss. 41, 45 and 46 of the *UCA*, and further found that its jurisdiction over public utility assets survived decommissioning by necessary implication, on the basis that the BCUC would otherwise be unable to regulate matters that are an "integral part" of its core mandate of "rate setting and protecting the supply system in a manner which safeguards the public interest."

The tribunal relied on the finding that it retained jurisdiction over decommissioned public utility assets to find that it could impose a term for sharing costs on future municipal use of the pipeline lands, pursuant to s. 32 of the *UCA*.

The City then filed an application for leave to appeal the Reconsideration Decision on June 30, 2020.

<u>BCCA Analysis and Findings</u>

The Court granted the application for leave to appeal, noting that the proposed appeal would raise novel issues of law concerning the jurisdiction of the BCUC *vis-à-vis* local governments. The fate of decommissioned public utility assets like pipelines is undoubtedly a matter of public importance, and parties noted the significant cost implications which arise from a decision on this issue.

Without making any findings on the merits of the case, the Court wrote that it was not persuaded by Fortis's submission that the appeal would be without arguable merit. Notwithstanding the existence of provisions in the *UCA* that appear to subordinate municipal authority in many areas to that of the BCUC, the issues on appeal concern powers that the tribunal found by necessary implication rather than through express statutory language. The Court noted that resort to statutory language delineating established powers between the BCUC and local governments is therefore of limited assistance at this stage.

The Court further noted that whether the implied powers claimed by the BCUC exist, namely to authorize decommissioning, to retain jurisdiction over decommissioned assets and to authorize those assets' abandonment in place on municipal lands, are not questions that have an obvious answer. They cannot be resolved by simple reference to the Supreme Court of Canada's decision in *ATCO*, whose application to statutory interpretation in this context is unclear. Since these and other issues of law would be determined on a correctness standard on appeal, the BCUC's own conclusions would not be given deference by this Court.

The Court was also not persuaded that the BCUC's mandate, express or implied, is so evidently broad as to render an appeal inarguable. It recognized that binding authority dating from the 1950s, when much of today's utility infrastructure was built, reflects a broader conception of the BCUC's public interest mandate relative to municipalities when it comes to utility infrastructure. However, the real issue is whether those same principles apply at the end of the infrastructure's life in comparison to when it/they went into service. As this issue has not been considered on appeal, and given the number of other pipelines which are approaching the end of their usefulness, leave ought to be granted so that this and related issues may be property considered by the Court.