REGULATORY LAW CHAMBERS

ISSUE: OCTOBER 2023 DECISIONS

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

IN THIS ISSUE:

SUPREME COURT OF CANADA

***Reference re Impact Assessment Act*, 2023 SCC 23**
Jurisdiction – Environmental Impact Assessment

Appeal

This was an appeal from an Alberta Court of Appeal ("ABCA") judgment regarding a reference by the Alberta's Lieutenant Governor in Council to the ABCA concerning the constitutionality of the federal *Impact Assessment Act* (the "*Act*") and the corresponding *Physical Activities Regulations* (the "*Regulations*"). The ABCA concluded that the *Act* and the *Regulations* were *ultra vires* the federal government and, therefore, unconstitutional in their entirety. The Attorney General of Canada ("Canada") appealed the ABCA decision to the Supreme Court of Canada ("SCC").

Decision

The SCC allowed the appeal in part finding the federal impact assessment scheme is largely unconstitutional.

Pertinent Issues

The SCC held that the sole issue in this appeal was whether the *Act* and the *Regulations* were *ultra vires* Parliament. In considering the issue, the SCC found the complex legislative scheme established by the *Act* and the *Regulations* to be two schemes in one. The first scheme, contained in ss 81 to 91 of the *Act*, dealt with projects carried out or financed by federal authorities on federal lands or outside Canada. According to the court, this portion of the scheme was clearly *intra vires*.

The second part of the scheme, consisting of the remaining portions of the *Act* and the *Regulation*, dealt with designated projects, as defined in the *Act*. The SCC found that Parliament plainly overstepped its constitutional competence in enacting this designated projects scheme, making it *ultra vires*.

Designated Projects

In relation to the second portion of the scheme, namely designated projects, the SCC conducted a division of powers analysis consisting of two steps: characterization and classification. The governing principles when assessing the characterization of the impugned legislation are the pith and substance analysis, characterization being distinct from classification, and there is a presumption of constitutionality.

The court found that the pith and substance of the "designated projects" component of the scheme was to assess and regulate designated projects with a view to mitigating or preventing their potential adverse environmental, health, social and economic impacts. Conversely, the pith and substance of the secondary component in ss. 81 to 91 of the *Act* was to direct the manner in which federal authorities that carry out or finance a project on federal lands or outside Canada assess the significant adverse environmental effects that the project may have.

The governing principle regarding classification of the impugned legislation is that the law is classified based on the on its main thrust or dominant characteristic, meaning its secondary effects are not the focus of the validity analysis. The fact that a valid law incidentally touches on a head of power belonging to the other level of government does not affect its validity.

The SCC held that classifying environmental legislation presents a challenge because the "environment" is not a head of power under ss 91 or 92 of the *Constitution Act, 1867* and that neither level of government has exclusive jurisdiction over the whole of the environment or over all environmental assessment. The SCC acknowledged that both levels of government can legislate in respect of certain aspects of environmental protection, including certain aspects of the environmental assessment of physical activities.

The court concluded that an impact assessment of a designated project could be required for reasons other than, or not sufficiently tied to, the project's possible impacts on areas of federal jurisdiction. Consequently, the court was not satisfied that it performed the funneling function necessary to maintain the scheme's focus on federal impacts. According to the court, the defined "effects within federal jurisdiction" went far beyond the limits of federal legislative jurisdiction, which overbreadth reinforces the conclusion that the pith and substance of the scheme cannot be classified under federal heads of power.

Ss 81 to 91 of the Act

The SCC noted that these provisions were not challenged as unconstitutional. The court found that ss 81 to 91 of the *Act* provided direction to federal authorities exercising their decision-making power in relation to projects that they undertook or funded themselves on federal lands or outside Canada. The SCC concluded that these provisions can be separated from the balance of the scheme and upheld as constitutional and, as a result, should not fall with the rest of the scheme.

ALBERTA COURT OF APPEAL

Judd v Alberta Energy Regulator, 2023 ABCA 296

Permission to Appeal – Error of Law

Application

Michael Judd applied for permission to appeal a decision of the AER, which dismissed a pre-hearing motion brought by Mr. Judd in a regulatory appeal of a pipeline licence (the "Pipeline Licence") granted to Pieridae Alberta Production Ltd. ("Pieridae").

Decision

The ABCA granted permission to appeal on a extricable question of law framed as follows: "when the AER panel considered whether the information requested by Mr. Judd was relevant and material to the issues in the regulatory appeal did they err in law by effectively confining themselves to the information obtained by the AER under *Directive 056, Energy Development Applications and Schedules* ("*Directive 056*")?"

Pertinent Issues

Background

The AER granted the Pipeline License following an application by Pieridae in accordance with *Directive 056*, and the *Pipeline Act*. Mr. Judd requested and was granted a regulatory appeal of the decision to issue the Pipeline Licence. After the AER established a panel of hearing commissioners ("Panel") to hear the regulatory appeal, Mr. Judd was concerned that the record of the decision maker produced by the AER for the regulatory appeal contained no information relevant to Pieridae's financial/capability assessment and compliance history, including its eligibility to acquire and hold a licence for energy development in Alberta. Mr. Judd brought a motion seeking an order requiring disclosure of information obtained by the AER under Directive 067, *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("*Directive 067*"), and Directive 088, *Licensee Life-Cycle Management* ("*Directive 088*"). Mr. Judd argued that the information was relevant and material to understanding the adverse impact the Pipeline Licence may have on him.

In deciding the motion, the Panel stated that it would consider whether the information requested by Mr. Judd is relevant and material to the proceeding. The Panel denied the motion holding that Pieridae's initial and ongoing licence eligibility were not included in the issues the Panel established for the regulatory appeal hearing. The Panel also held that the determination of licence eligibility under *Directive 067* is a separate regulatory process from deciding an application for a new license under the *Pipeline Act* and that the holistic licensee assessment referred to under *Directive 088* is also a separate regulatory process from deciding an application for a new licence under the *Pipeline Act*.

The Panel concluded that Mr. Judd had failed to address how the information he requested may relate to the decision's direct and adverse effect on him or how it may benefit the AER in making its decision on the regulatory appeal.

Mr. Judd submitted that the AER made an error of law by treating information collected by the AER as siloed under its practice directives, failing to consider that:

- determining relevance and materiality based on the AER's separation of regulatory processes; that is, procedural distinction between *Directives 067* and *088* and Mr. Judd's regulatory appeal, has no support in the AER governing enactments,
- eligibility to hold a pipeline licence is a requirement when applying for a licence and the financial and other capacities of an applicant to meet their regulatory obligations remain a relevant and material consideration for the AER throughout the energy development life-cycle, and
- the AER must determine the issues in the regulatory appeal concerning the assessment of risk associated with Pieridae, as the pipeline licensee.

ABCA Decision

The ABCA held that a determination of relevance and materiality is ordinarily a question of mixed fact and law and that Mr. Judd identified the following extricable question of law: when the panel considered whether the information requested by Mr. Judd was relevant and material to the issues in the regulatory appeal, did they err in law by effectively confining themselves to the information obtained by the AER under *Directive 056*?

The court found that the issue raised by Mr. Judd involves his ability to fully understand the adverse impact the Pipeline Licence may have on him; that is, to know the case against him. According to the ABCA, the questions was whether the Panel fell into reviewable error by incorrectly restricting the scope of potentially relevant and material information. Although the decision Mr. Judd seeks to appeal was an interlocutory one, the court found the question of general importance because the answer has potential application beyond this regulatory appeal.

The ABCA was of the view that the issue on appeal was also significant to the decision itself and that Mr. Judd's argument that the AER's governing enactments do not support the Panel's emphasis on the separation of regulatory processes has sufficient merit to warrant review by the ABCA.

ALBERTA ENERGY REGULATOR

***Invitation for Feedback on Proposed New Requirements for Rock-Hosted Mineral Resource Development,* AER Bulletin 2023-36**
Minerals – Development

The AER sought feedback on its proposed new *Draft Directive: Rock-Hosted Mineral Resource Development* ("*Draft Directive*"). The Draft Directive sets out the industry's requirements for rock-hosted mineral resource development and covers the entire development life-cycle. The AER was also proposing to prepare guidance and change any existing directives to incorporate rock-hosted mineral development.

The *Draft Directive* was developed pursuant to the *Mineral Resources Development Act* ("*MRDA*") that received royal assent on December 2, 2021. The *MRDA* gives the AER the authority to provide for the safe, efficient, orderly, and environmentally responsible development of Alberta's mineral resources.

***Reclamation Liability Reduction Program Being Developed,* AER Bulletin 2023-37**
Oil and Gas – Facilities

The AER is implementing a reclamation liability reduction program (the "Program"), with an anticipated release in the spring of 2024. The Program is intended to allow licensees to request a temporary reduction of the liability values used in the AER's liability management programs.

The reduction may be requested once all abandonment, remediation and reclamation work has been completed but before a reclamation certificate is issued under the *Environmental Protection and Enhancement Act* ("*EPEA*") since it may take several years before vegetation is fully established and the site becomes eligible for a reclamation certificate. As such, the site may be eligible for a reduction in liability value in the meantime.

The Program will apply to wells and facilities licensed under *Directive 056: Energy Development Applications and Schedules* and the liability value reduction will be valid for five years or until a reclamation certificate is obtained, whichever occurs first.

***Temporary Pause on New Pipeline Applications,* AER Bulletin 2023-38**
Oil and Gas - Pipelines

The AER temporarily paused new pipeline application submissions through OneStop from November 6, 2023, to November 16, 2023, in response to the new *Pipeline Rules* release scheduled for November 15, 2023.

The temporary pause is intended to ensure efficient processing of applications submitted before the new *Pipeline Rules* come in effect on November 15, 2023. This approach should allow for a more seamless transition to the updated regulatory framework.

Applications submitted before November 6, 2023, will be processed in accordance with the current *Pipeline Rules* and all associated regulatory instruments. Applications received after November 16, 2023, will be processed in accordance with the amended *Pipeline Rules* and all associated regulatory instruments.

ALBERTA UTILITIES COMMISSION

***2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities,* AUC Decision 27388-D01-2023**

Performance-Based Regulation Plan - Rates

Application

In Bulletin 2022-006, issued on May 26, 2022, the Alberta Utilities Commission ("AUC") initiated Proceeding 27388 to establish the parameters of the performance-based regulation ("PBR") plans that will start in 2024, for Alberta distribution facility owners ("DFOs").

Decision

In the decision, the AUC established the parameters of the third generation ("PBR3") plan to be implemented for the 2024 to 2028 period applying to ATCO Electric Ltd., FortisAlberta Inc., ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc. ("EPCOR") (the "Electric Distribution Utilities"); ATCO Gas and Pipelines Ltd. and Apex Utilities Inc. (the "Gas Distribution Utilities") (collectively, the "Distribution Utilities").

Pertinent Issues

The PBR3 plan builds upon the AUC's second-generation PBR plan, which was in effect from 2018 to 2022. The AUC set the PBR3 plan parameters as described below.

The AUC set the inflation ("I") factor to use: (i) the Alberta Fixed Weighted Index ("FWI") labour price index instead of the Alberta Average Weekly Earnings ("AWE"); (ii) an updated 60 percent labour and 40 percent non-labour weighting; and (iii) a forecast and true-up approach for the I factor instead of the lagged approach.

The AUC approved a total factor productivity ("TFP") growth factor of 0.1 percent, based on industry TFP growth and a stretch factor, and an additional benefit-sharing provision in the form of an X-factor premium of 0.3 percent. Except for the calculation of the K-bar, the total X-factor to be used in PBR3 is 0.4 percent, inclusive of the benefit-sharing premium. For K-bar calculation purposes, the X-factor of 0.1 percent must be used.

The AUC modified the funding mechanisms for each of the Type 1 and Type 2 capital from the ones used in prior PBR plans. Type 1 capital includes projects of a type that is extraordinary and not previously included in the distribution utility's rate base, if the project is required by a third party. Type 2 capital, managed under the K-bar mechanism, includes all or most other capital that does not qualify for either Y factor or Z factor treatment, whether fully funded under the I-X mechanism or not. The AUC expanded the criteria used in the PBR2 plan to provide for funding for capital directly caused by applicable law related to net-zero objectives, and introduced an expanded accounting test to calculate the Type 1 capital tracker amount. The AUC approved the following new alternative remuneration scheme on a pilot basis:

- For Type 1 capital, the AUC approved a capital tracker mechanism with some modifications for the eligibility criteria to provide funding for expenditures directly caused by applicable law related to net-zero objectives. The AUC also introduced an expanded accounting test to calculate the Type 1 capital tracker amount.

- For Type 2 capital, the AUC approved the K-bar mechanism used in PBR2 with some modifications, including using a five-year average of 2018-2022 historical actual capital additions and a customer growth escalator instead of the Q factor. The AUC further clarified that an X-factor of 0.1 percent must be used in the K-bar accounting test.

- The AUC also implemented a new alternative remuneration scheme on a pilot basis, which allows utilities to earn a return on specific operation costs.

The AUC introduced two additional benefit-sharing provisions to the PBR3 plan. First, an X-factor premium of 0.3 percent, and second, an asymmetric, two-tiered earnings sharing mechanism ("ESM") with the following parameters:

- A deadband of 200 basis points above the approved return on equity ("ROE") for a given year with no customer sharing. Further, no sharing with customers through an ESM occurs below the approved ROE rate.

- A first tier of sharing between 200 basis points and 400 basis points above the approved ROE for that year within which a distribution utility retains 60 percent of the incremental earnings and customers receive 40 percent of the incremental earnings.

- A second tier of sharing at 400 basis points above the approved ROE for that year, where utilities retain 20 percent of the incremental earnings and customers receive 80 percent of incremental earnings.

The AUC determined that there was no longer a need to trigger the reopener review when an achieved ROE exceeds the approved ROE by 300 basis points in two consecutive years. Other reopener provisions remained unchanged from the first two PBR terms. The AUC also determined that the efficiency carryover mechanism ("ECM") will not be included in the PBR3 plan.

The AUC directed the Distribution Utilities to track efficiencies, using: (a) controllable operations and maintenance (O&M) per customer; (b) controllable O&M per kilometre (km) of line (pipe); (c) total cost per customer, broken out by O&M and capital additions separately; and (d) total cost per km of line (pipe), broken out by O&M and capital additions separately. The AUC also approved EPCOR's proposed treatment of its customer-specific rates in the PBR3 plan.

The AUC did not direct any changes to regulating the Electric Distribution Utilities under the price-cap plan and Natural Gas Distribution Utilities under the revenue-per-customer plan.

The remaining parameters of the PBR3 plan, such as the annual rate changes, price-cap vs revenue-per-customer cap approaches, Y factor, Z factor, service quality, financial reporting and annual reporting requirements were unchanged from those established in the PBR2 plans.

***Enforcement Staff of the Alberta Utilities Commission Penalty for Contraventions 1-5*, Decision 26379-D04-2023**

Enforcement – Penalties

Application

This was a penalty determination as part of the second phase of the AUC's enforcement proceeding against Green Block Mining Corp. ("Green Block"), formerly known as Link Global Technologies Inc. ("Link Global"). In the phase one of the enforcement proceeding, the AUC found that Green Block committed five contraventions related to the unauthorized operation of its power plants contrary to the *Hydro and Electric Energy Act* ("*HEEA*") and *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* ("*Rule 007*"). In this proceeding, the AUC considered the appropriate penalty for those contraventions.

Decision

The AUC ordered that Green Block must pay an administrative penalty in the amount of $298,250.00 in total for the five contraventions.

Pertinent Issues

Overview

In the first phase of this enforcement proceeding, the AUC determined that Green Block operated three power plants in Alberta between 2019 and 2021 without the required approvals. The AUC issued Decisions 26379-D01-2023, 26379-D02-2023 and 26379-D03-2023 regarding the contraventions. This decision follows the second phase of the enforcement proceeding, where typically, the penalty is determined.

In Decision 26379-D02-2021, the AUC approved the terms of a partial settlement between Green Block and the AUC's enforcement staff that included agreement on three contraventions and the administrative penalty range. The AUC imposed a total administrative penalty of $60,000 for Contraventions 1-3.

In Decision 26379-D02-2021, the AUC found that Green Block failed to inform the AUC in a timely manner of its shutdown activities of the Sturgeon plant in breach of the AUC's Enforcement Order 26379-D01-2021. The AUC ordered an administrative penalty of $17,000 for Contravention 4.

In Decision 26379-D03-2022, the AUC imposed an administrative penalty of $221,250 for Contravention 5, which was in relation to Green Block's operation of the Westlock plant without approval.

As a result, the AUC ordered that Green Block must pay an administrative penalty in the amount of two hundred and ninety-eight thousand, two hundred and fifty dollars ($298,250.00) pursuant to sections 63(1)(a) and 63(2)(a) of the *Alberta Utilities Commission Act*. The payment may be made via wire transfer, certified cheque, or bank draft made out to the General Revenue Fund of Alberta and delivered to the AUC within 30 business days of the date of this order.

Related to the administrative penalty for Contraventions 1-5 was the issue of economic benefit, if any, gained by Green Block by its wrongdoing. The AUC decided to address the economic benefit issue separately, following an oral hearing scheduled for October 19-20, 2023.

Sanctioning Purposes and Principles

In determining the penalty amounts, the AUC considered that the purpose of its sanctioning authority is to achieve general and specific deterrence, encourage compliance and protect the public. In addition, administrative sanctions are intended to be protective and preventative, not punitive. Proportionality is important when assessing an administrative penalty, and each monetary penalty must be proportionate to the circumstances of the individual offender. The issue of proportionality plays a prominent role in the consideration of the administrative penalty for Contravention 5, for which there was no agreement between the parties. Law on sanctioning did not play a significant role for Contraventions 1-4, where the contravention and penalties were agreed upon by the parties or previously determined by the AUC.

***Residential Standards of Service and Maximum Investment Levels – Phase 2,* AUC Decision 27658-D02-2023**

Electricity – Rates

Application

In September 2022, the AUC established Proceeding 27658 to examine the standards of service and the associated maximum investment levels (“MILs”) for residential services. Proceeding 27658 progressed in two phases: the first phase established the MILs for 2023, and the second phase addressed MILs for 2024 and future years thereafter, considering the following principles: the affordability of connecting to the electric grid; what is a prudent level of investment by utilities for those services; and, the proper allocation of costs between new or upgrading customers, developers and existing customers. The AUC set 2023 MILs in Decision 27658-D01-2022, which concluded the first phase of Proceeding 27658. This decision dealt with the second phase of the proceeding.

Decision

The AUC held that it remains just and reasonable to allow electric distribution utilities to invest in new residential customer connections up to a prescribed maximum MIL amount. The AUC approved a residential MIL of $3,016 for all four electric distribution utilities for 2024, to be escalated annually by I-X for the remainder of the 2024-2028 performance-based regulation (“PBR”) term. For MILs related to street lighting installed in a new development, the AUC found that the MIL should be paid to the municipality where the new development was constructed.

Pertinent Issues

A MIL is the maximum dollar amount that a distribution utility can invest in a new customer service connection and add to its rate base. The distribution utility pays some or all of the costs incurred in the connection of a new customer up to the maximum amount allowed and, in turn, capitalizes these costs and recovers the investment over time through the rates it charges to customers. To the extent that connection costs exceed the MIL, these costs are borne directly by the connecting customer, rather than being socialized across customers through rates.

Should MILs be Retained?

The AUC provided an overview of MILs and endorsed, in general, the 10 MILs principles established by precedent. The AUC found that, while MILs are not required by the statutory scheme, they are a proportionate way to compensate the distribution utilities for operational and ownership responsibilities incurred in relation to new customer-related connection infrastructure. The AUC also considered the regulatory compact but concluded that the regulatory compact does not dictate a particular outcome with respect to MILs. The AUC examined the statutory scheme established by the *Electric Utilities Act* (“*EUA*”) and concluded that the statutory scheme does not require the MILs to be available to utilities, nor a particular methodology for calculating MILs. The AUC, however, found some support in the statutory scheme for the principle that some basic level of utility investment in new customer-related connection infrastructure was merited. The AUC also found it unnecessary to decide whether the elimination of MILs entirely would be contrary to the statutory scheme since the MILs were retained.

The AUC determined that balancing provision of service with the recovery of costs associated with that service under the regulatory compact favours a basic level of investment by distribution utilities in the connection infrastructure that they will ultimately own and operate.

What Principles Should Govern MILs Going Forward?

The AUC established the following principles that should govern the setting of residential MILs:

(a) MILs should be consistent, transparent and simple to administer;

(b) MILs should ensure new customers are not imposing costs on other customers for which they should not be responsible;

(c) MILs should provide price signals to customers and developers to incent the most cost efficient connections possible for their current and future needs; and

(d) MILs should subsidize a service connection at a basic level of service, and not premium levels of service. Basic service is the level of service that a typical Albertan requires to light their homes and power their electronics and household appliances.

The AUC applied these four principles and determined that MILs should be set to cover a reasonable estimate of the cost to provide a basic electrical service connection, which corresponds to 100-amp, overhead service.

Quantum of MILs for the 2024-2028 PBR Term

By taking the average of the cost estimates to provide 100-amp service of all four distribution utilities, the AUC determined that the MIL for 2024 for each electric distribution utility will be $3,016 per lot, to be escalated by I-X for the duration of the PBR term. The AUC stated that as a consequence of the application of the four principles and the guidance provided in this decision the distribution utilities should be able to provide better information in the future relevant to the calculation of MILs. Accordingly, the AUC noted that the determinations in this decision may need to change in the future, based on further evidence provided.

Miscellaneous

The AUC recognized that design standards may impact new connection costs and advised that it may choose to explore the issue of standards further in a future proceeding. The AUC also found that a municipality where new street lights are installed and operated is entitled to receive the corresponding MIL.

***AUC Determination of the Cost-of-Capital Parameters for 2024 and Beyond,* AUC Decision 27084-D02-2023**

Gas - Rates

<u>Application</u>

The AUC initiates a mandatory review of cost-of-capital parameters every five years, subject to mid-term reopeners, on its own motion or upon application from interested parties. The cost-of-capital parameters apply to the following utilities: AltaLink Management Ltd; Apex Utilities Inc; ATCO Electric Ltd; ATCO Gas and Pipelines Ltd; ENMAX Power Corporation; EPCOR Distribution & Transmission Inc; FortisAlberta Inc; and KainaiLink LP.

The AUC established this proceeding in January 2022, as a bifurcated process to determine the return on equity (“ROE”) and deemed equity ratios. Decision 27084-D01-2022, issued after the first part of the proceeding was completed, established the cost-of-capital parameters for 2023. This decision addressed the second part of the proceeding and established a formulaic approach for setting ROE in 2024 and each year thereafter, including the deemed equity ratios for the utilities.

<u>Decision</u>

The AUC adopted the following formulaic approach for calculating the ROE, utilizing the equity risk premium (“ERP”) methodology:

$$ROE_t = 9.0\% + 0.5 \times (\text{YLD}_t - 3.10\%) + 0.5 \times (\text{SPRD}_t - \text{SPRD}_{base})$$

Pertinent Issues

The AUC adopted a formulaic approach, implementing an ERP-based two-factor formulaic approach similar to the one utilized by the Ontario Energy Board. The AUC's generalized formulaic approach can be specified as:

$$ROE_t = 9.0\% + 0.5 \times (YLD_t - 3.10\%) + 0.5 \times (SPRD_t - SPRD_{base})$$

The approved ROE is determined by adjusting the notional ROE of 9.0 per cent approved in this decision by the difference in forecast long-term Government of Canada (GoC) bond yield (YLDt) and utility bond yield spread (SPRDt) from their base values of 3.10 per cent and the bond yield spread for the month of February 2023, respectively. These forecasts will be calculated by the Commission in early November of each year as follows:

(i) The forecast long-term GoC bond yield will be calculated as the weighted average of (a) the 30-year GoC bond yield forecasts published by Royal Bank of Canada (RBC), TD Bank (TD) and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (b) the naïve forecast representing the average long-term GoC bond yield over the period October 1 to October 31 each year preceding the test year (0.25 weight). In other words, the published forecasts and actual data in October 2023 will be used to set the ROE for 2024, data from October 2024 will be used to set the ROE for 2025, and so on.

(ii) The prevailing utility bond yield spread will be calculated as the average difference between the 30-year A-rated Canadian utility bond yield and the long-term GoC bond yield over the period October 1 to October 31 of each year preceding the test year (i.e., the utility bond yield spread in October 2023 will be used to determine the ROE for 2024, and so on).

The AUC did not determine in this proceeding the cost-of-capital parameters for the various investor-owned water utilities under its jurisdiction. However, the AUC held that it may consider in other proceedings the determinations it made in this proceeding in relation to the ROE and deemed equity ratios.

The AUC also determined that the deemed equity ratios should be reviewed every five years or whenever the ROE formula is reviewed, whichever occurs first.

AUC Determination of the Cost-of-Capital Parameters in 2024 and Beyond – Formula Base Values, **AUC Decision 27084-D03-2023**
Gas - Rates

Application

In Decision 27084-D02-2023, the AUC determined the value of each of the base inputs to the formula, except the utility bond spread for the base period ("$SPRD_{base}$"). The AUC determined that it would use the average utility bond yield spread for February 2023 for $SPRD_{base}$. As the spread data from February 1 to February 28, 2023, was not available on the record, the AUC directed ATCO Utilities to perform the necessary calculations and provide the average utility bond yield spread in February 2023. In accordance with this direction, ATCO Utilities filed the calculations and resulting utility bond yield spread value of 1.58 per cent.

Decision

The AUC was satisfied by the calculations submitted by ATCO Utilities and confirmed on a final basis the following base values in the formula that will determine the return on equity in 2024 and subsequent years:

$$ROE_t = 9.0\% + 0.5 \times (YLD_t - 3.10\%) + 0.5 \times (SPRD_t - 1.58\%)$$

Enforcement Staff of the Alberta Utilities Commission Settlement Agreement with Persist Oil & Gas Inc., **AUC Decision 28370-D01-2023**
Market - Enforcement

Application

Enforcement staff of the AUC ("Enforcement Staff") applied to the AUC for approval of a settlement agreement between Enforcement Staff and Persist Oil & Gas Inc. ("Persist") related to a contravention arising out of the operation of a power plant without the required approval, including exceeding the noise levels permitted by *Rule 012: Noise Control* ("Settlement Agreement").

Decision

The AUC concluded that the Settlement Agreement is in the public interest and approved it as filed. As a result, the AUC imposed a total penalty of $112,900, consisting of an administrative penalty of $11,475 and disgorgement of $101,425, which was based on the gross economic benefits earned during the operation period.

Pertinent Issues

The AUC considered and approved the Settlement Agreement under ss 8, 23, and 63 of the *Alberta Utilities Commission Act*. The AUC applied the "public interest test," which allows departing from a joint submission only if it would bring the administration of justice into disrepute or is otherwise contrary to the public interest.

In reaching the settlement, the parties considered factors listed in *Rule 013: Criteria Relating to the Imposition of Administrative Penalties* ("*Rule 013*"), such as the harm resulting from the contraventions, the material benefits to Persist and the duration of the harm, which was approximately one year.

Enforcement Staff also considered the mitigating factors outlined in *Rule 013*, noting that Persist was responsive and cooperative upon learning of the contraventions.

Enforcement Staff pointed out that reducing the disgorgement of economic benefits proposed in the Settlement Agreement was in the public interest, allowing the parties to address harm creatively and responsively, with guidance from *Rule 013*. The AUC did not find any reasons to depart from the Settlement Agreement and approved it as filed.

Alberta Electric System Operator Needs Identification Document Application, AltaLink Management Facility Applications – Georgetown Solar Project Connection, **AUC Decision 28327-D01-2023**
Solar Power – Facilities

Application

Georgetown Solar Inc. ("Georgetown Solar") has an AUC approval to construct the Georgetown Solar + Energy Storage Project (the "Power Plant"), which includes a solar power plant, a battery energy storage system and the Mossleigh 1051S Substation.

To connect the Power Plant to the Alberta Interconnected Electric System ("AIES"), the Alberta Electric System Operator ("AESO") filed a needs identification document ("NID") application. AltaLink Management Ltd. ("AML") filed facility applications for approval to construct and operate the facilities to meet the need identified by the AESO.

Decision

The AUC approved the NID application from the AESO and the facility applications submitted by AML.

Pertinent Issues

AESO NID Application

The AESO filed a NID application to add one 240-kilovolt ("kV") circuit to connect the approved Mossleigh 1051S Substation to the existing Transmission Line 924L.

The AESO stated that the proposed transmission development provides a reasonable opportunity for AML to exchange electric energy and ancillary services, and that the proposed transmission development is consistent with the AESO's long-term plans. The AESO and AML conducted a joint participant involvement program. The AUC found that the applications comply with the information requirements set out in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* and that the proposed transmission project was consistent with meeting the approved need and the requirements of the AESO's functional specification.

The AESO conducted studies to assess the impact the development and associated generation would have on the transmission system. The AESO's studies indicated that the connection may cause thermal violations, which may require generation to be curtailed. The probability of required pre-curtailment would depend on generation profiles and operating conditions. Closer to the in-service date, if the AESO determines that congestion will arise under Category A conditions, the AESO may make an application to the AUC to obtain approval for an exception under s 15(2) of the *Transmission Regulation*.

AML Facility Applications

To meet the need identified in the AESO's application, AML filed facility applications, which proposed to:

- modify two structures on the existing Transmission Line 924L and install a new steel lattice structure at the midspan of these two structures;
- construct the 150 meters, 240-kV Transmission Line 924AL; and
- install a new telecommunications tower, up to 40 meters in height, within the Mossleigh 1051S Substation.

The AUC found that AML's facility applications comply with the information requirements set out in *Rule 007* and that they were consistent with the need identified by the AESO.

The AUC accepted the conclusion of the environmental evaluation report submitted for the applied-for facilities, which indicated that the incremental impacts on the environment and landowners would be minimal, considering the details of the project and AML's mitigation measures and operational standards.

***AltaLink Management Ltd. Vauxhall Solar Farm Connection*, AUC Decision 28440-D01-2023**
Communication - Facilities

Application

AltaLink Management Ltd. ("AML") applied for approval to connect Solar Krafte Utilities Inc.'s ("Solar Krafte") Vauxhall Solar Farm to the Alberta Interconnected Electric System ("AIES") through a new 100-meter, 138-kilovolt ("kV") Transmission Line 763BL ("TL 763BL"). AML further applied to alter the existing Transmission Line 763L ("TL 763L") and to install approximately 3 kilometers of underground fibre optic cable (collectively, the "Project").

Decision

The AUC found the Project to be in the public interest and approved the application as filed.

Pertinent Issues

Solar Krafte has AUC approval to construct and operate the 60-megawatt ("MW") Vauxhall Solar Power Plant (the "Power Plant") and Solstice 549S Substation (the "Substation"), in the Vauxhall area.

The AESO approved the need to connect Solar Farm to the AIES through the abbreviated needs approval process. To meet the need identified by the AESO, AML filed applications with the AUC for approval of the required facilities.

The AUC reviewed the facilities and connection applications for the TL 793BL, TL 763L and the fibre optic cable and determined that the information requirements specified in *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* ("*Rule 007*") were met.

The AUC was satisfied that AML's participant involvement program met the requirements of *Rule 007.* The AUC accepted that the Project's environmental effects would be minimized with no significant adverse environmental impact.

Based on the foregoing, the AUC considered the Project to be in the public interest in accordance with s 17 of the *Alberta Utilities Commission Act* ("*AUC Act*").

***ATCO Electric Ltd. Dog Rib Fibre Optic Connection Project,* AUC Decision 28463-D01-2023**
Communications - Facilities

Application

ATCO Electric Ltd. ("AE") applied for approval to construct and operate the 185-meter ("m") ELADFO021 underground fibre optic telecommunications cable, from AE's existing Dog Rib 2082S Substation to its existing optical protection ground wire on Transmission Line 9L162 (the "Project"). The Project is located 23 kilometers northwest of Fort McMurray, Alberta.

Decision

The AUC approved the application from AE to construct and operate the Project.

Pertinent Issues

AE submitted that the Project is needed to replace end-of-life telecommunications equipment that is no longer supported by the manufacturer. AE proposed to install an underground fibre optic cable to maintain connection between the substation and the electric system's telecommunications network.

The AUC was satisfied that the application met the requirements set out in *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines.* The AUC found that the Project's environmental impact will be minimal given that the 185 meter long proposed cable will be installed underground, beneath pre-disturbed land using bore/directional drilling. The AUC was further satisfied that the consultation with potentially interested parties was appropriate and that Indigenous consultation was not required, as there was no known potential impact on Aboriginal rights and traditional uses.

***ATCO Electric Ltd. Notice of Dispute for Micro-Generation,* AUC Decision 28319-D01-2023**

Solar Power - Micro-Generation

Application

Dale Sunderland, a "customer" under the *Micro-Generation Regulation* ("*MGR*")*,* submitted a micro-generation application to ATCO Electric Ltd ("AE") proposing to build a 148.5-kilowatt ("kW") solar photovoltaic system at the Sunderland Hog Farm in Paradise Valley, capable of producing annually approximately 296,667-kilowatt hours ("kWh") of electric energy. ATCO Electric ("AE"), an "owner" under the *MGR*, disputed the application based on annual consumption history at the site, alleging that the generator is oversized since the site's energy consumption in 2022 was 208,560 kWh. AE filed a notice of dispute with the AUC pursuant to s 2(2) of the *MGR*.

Decision

The AUC found that D. Sunderland's proposed generating unit qualifies as a "micro-generation generating unit" under s 1(1)(h) of the *MGR*.

Pertinent Issues

In essence, the parties disputed whether the generating unit meets the condition in s 1(1)(h)(ii) of the *MGR*, which specifies that, *inter alia*, a micro-generating unit is intended to meet all or a portion of the customer's total annual energy consumption at the customer's site or aggregated sites.

AE argued that, because the generating unit will have the capability to produce 296,667 kWh, which exceeds the site's 2022 annual consumption of 208,560 kWh, it is oversized and does not satisfy the requirements of *MGR* s 1(1)(h)(ii). D. Sutherland submitted that the requirement is met because the annual electricity needs are based on the site's average energy consumption in the five-year period of 2018-2022, which was 309,360 kWh.

The AUC interpreted s 1(1)(h)(ii) of the *MGR* to permit consideration of a range of historical energy consumption data at the site when appropriate in the circumstances, rather than applying a narrow reading of the section and considering only the most recent full year of consumption. The AUC did not consider this interpretation to be contrary to the intent of the *Electric Utilities Act*.

In determining whether the generating unit satisfies s 1(1)(h)(ii), the AUC found that it was appropriate to use the five-year historical average energy consumption at the site, given the nature of the farming industry, including the associated fluctuation in energy needs and the atypical conditions affecting the site's energy consumption in the very dry 2021 and 2022 years. The AUC determined that the generating unit satisfied s 1(1)(h)(ii) and met all other requirements of the *MGR*.

***ATCO Electric Ltd. Sweeney Creek Telecommunications Tower Site Project,* AUC Decision 28360-D01-2023**

Communications – Facilities

Application

ATCO Electric Ltd. ("AE") applied to the AUC for approval to construct and operate the new Sweeney Creek 1090 Telecommunications Tower Site (the "Project"), located on Crown land, approximately 50 kilometers northwest of Worsley, Alberta.

Decision

The AUC approved the facility application from AE for the Project.

Pertinent Issues

The Project consisted of a 110-meter self-supported steel lattice telecommunications tower, associated control buildings and, electric and telecommunications equipment. AE submitted that the Project was needed to improve the reliability and capacity of AE's telecommunication network in the northwest area of the province. The site will complete a communication loop between AE's existing Sock Lake and Clear Hills telecommunications tower sites.

To provide power to the site, AE intended to install a hybrid power system consisting of a solar array, a battery energy storage system and a generator. The solar array will have a power generation output of 61 kilowatts. The site will not be connected to the Alberta Interconnected Electric System and AE did not file a power plant application as the capability of the system was less than one megawatt and the generated power was intended for AE's own use.

The AUC determined that the application satisfies the information requirements specified in *Rule 007*. The AUC found that the participant involvement program for the Project met the requirements of *Rule 007* and was satisfied there were no outstanding concerns. The AUC accepted that the environmental impacts of the proposed development were expected to be minimal, since the Project had a small footprint and AE committed in the environmental evaluation and the environmental protection plan to implementing mitigation.

The AUC accepted that an application for a hybrid power system is not required, as per s 4.1 of *Rule 007*, given that the requirements of s 13 of the *Hydro and Electric Energy Act* "(*HEEA*") were met. The AUC found the Project in the public interest in accordance with s 17 of the *Alberta Utilities Commission Act* ("*AUC Act*").

***ATCO Electric Ltd. Touchwood Telecommunications Tower Connection Project*, AUC Decision 28442-D01-2023**

Communications - Facilities

Application

ATCO Electric Ltd ("AE") applied to decommission and salvage the Touchwood Microwave Power Plant and alter the Touchwood Telecommunications Tower Site by connecting it to the Alberta Interconnected Electric System ("AIES").

Decision

The AUC approved AE's applications to decommission and salvage the Touchwood Microwave Power Plant, and to alter the Touchwood Telecommunications Tower Site.

Pertinent Issues

The AUC found that the proposed project was in the public interest in accordance with s 17 of the *Alberta Utilities Commission Act.* The AUC found that the applications comply with the information requirements set out in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* ("*Rule 007*") and that the participant involvement program met the requirements of *Rule 007*. Further, the AUC believed that the temporary noise from the project would comply with *Rule 012: Noise Control.* The AUC found the environmental impacts of the project to be minimal since no vegetation clearing or ground disturbance was required.

***ATCO Gas and Pipelines Ltd. Swanhills Loop Transmission Project,* AUC Decision 28431-D01-2023**

Gas - Facilities

Application

ATCO Gas and Pipelines Ltd. ("AG") applied for approval to construct and operate the Swanhills Loop Transmission Project, consisting of 4.6 kilometers ("km") of new 168.3-millimeter ("mm") high-pressure natural gas pipeline (the "Project"), in the area of Spruce Grove, Alberta.

Decision

The AUC approved the application from AG to construct and operate the Project.

Pertinent Issues

The Project will connect AG's existing 323.3-mm Swan Hills Transmission Pipeline to a proposed regulator station in the Spruce Grove area. The new pipeline will assume the current demand of the existing Stony Plain transmission line and bring additional gas supply from the existing Swan Hills Transmission line for the future needs of the Spruce Grove area.

The AUC assessed and approved the need for the Project in Decision 25663-D01-2021. The AUC determined that the application met the requirements set out in *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designation, Hydro Developments and Gas Utility Pipelines*.

The AUC accepted that AG will comply with the *Water Act* requirements for all watercourse and wetland crossings and that AG will obtain a *Historical Resources Act* clearance before commencing construction. The AUC accepted AG's commitment to follow the environmental protection plan in order to reduce the risk of adverse environmental impacts associated with the construction and operation of the Project. The AUC found the smaller diameter pipe safe and sufficient for the current and future needs. The AUC held that the Project, including the pipe diameter reduction, was the least costly alternative.

***ATCO Gas and Pipelines Ltd. Unaccounted-For Gas Rider D and Rider P,* AUC Decision 28406-D01-2023**

Gas - Rates

Application

ATCO Gas ("AG"), a division of ATCO Gas and Pipelines Ltd., applied for approval of its 2023-2024 unaccounted-for gas ("UFG") Rider D and Rider P, effective November 1, 2023. AG calculated Rider D to increase from the currently approved value of 1.271 percent to 1.418 percent, and Rider P to increase from 1.270 percent to 1.397 percent. In the proceeding, AG revised these values to be 1.346 for Rider D and 1.328 for Rider P.

Decision

The AUC approved the application from AG, for approval of the UFG rate Rider D and Rider P, as amended, effective November 1, 2023.

Pertinent Issues

UFG Calculations and Rider D and Rider P Amounts

Both rate riders are similarly designed. Historically, Rider D was calculated annually using the most recent three-year average of AG's annual UFG percentages, derived by dividing UFG by system deliveries. Rider P was similarly calculated using the most recent three-year average of annual UFG percentages but used system receipts as the denominator to calculate the annual UFG recovery requirement.

In the application, AG calculated Rider D and Rider P using the most recent three-year averages. The AUC observed that Apex Utilities Inc. calculated its UFG percentages using the most recent five-year historical average. As UFG amounts are driven by generally unpredictable causes, they are inherently variable. In response to an AUC information request ("IR"), AG agreed that a five-year average will provide a smoother and more stable representation of UFG over time. AG recalculated the initially applied-for rate rider percentages using the five-year averages arriving at rates of 1.346 for Rider D and 1.328 for Rider P.

The AUC asked AG to comment on the apparent recent upward trend in annual UFG percentages. The AUC determined that the increase in UFG was an unintended by-product of implementing a new geographical information system. While the cost of UFG is ultimately recovered from customers, the AUC determined that an increase in UFG in 2021 and 2022 is likely to be a temporary issue, which was not a cause of concern, at the time of this decision.

Compliance with Previous AUC Directions

The AUC was satisfied with the information provided by AG in response to directions issued in Decision 27583-D01-2022 regarding ATCO Gas' 2022 UFG Rider D and Rider P. As directed, AG provided:

- Explanations of seasonal UFG differences, measurement corrections and reasons for increases or decreases;
- Information on practices and procedures it has employed to reduce UFG;
- Details for all measurement adjustments showing the reconciliation of prior years' data; and
- Net results of the adjustments to UFG, both in terms of energy and as a percentage of receipts.

In Decision 27583-D01-2022, the AUC directed AG to discuss whether the monthly line heater usage and associated carbon levy table included in previous UFG Rider D and Rider P applications better belong in the load balancing deferral account rider (Rider L) application dealing with the recovery of the carbon levy amounts. AG explained that the gas usage of Line Heaters can now be measured and, as a result, it does not consider line heater usage as a source of UFG anymore. The AUC agreed with the recommendation by AG to report the carbon levy associated with line heater usage in future Rider L applications.

***Aura Power Renewable Ltd. Decision on Preliminary Question Application for Review of Decision 27488-D01-2023 Burdett Solar Project,* AUC Decision 28409-D01-2023**

Solar Power – Review and Variance

Application

Aura Power Renewables Ltd. ("Aura") applied for a review and variance of AUC Decision 27488-D01-2023, regarding the Burdett Solar Project (the "Decision").

Decision

The AUC denied Aura's application for review and variance.

Pertinent Issues

In the Decision, the AUC denied the application from Aura to construct and operate the 17.5-MW Burdett Solar Project (the "Project"), to connect the Project to the FortisAlberta Inc. distribution system, and to transfer ownership of the Project.

The AUC's review process has two stages. In the first stage, a review panel decides if there are grounds to review the original decision (the "Preliminary Question"). If yes, it moves to the second stage where it decides whether to confirm, vary or rescind the original decision (the "Variance Question").

Review Panel Findings

There are New Facts Material to the Decision; Specifically, Additional Post-Construction Bird Fatality Data for BluEarth Renewables Inc.'s Burdett Solar Project, Immediately Adjacent to the Project Site

Aura submitted that a 2022 post-construction bird fatality monitoring report for BluEarth Renewables Inc.'s ("BluEarth") Burdett Solar Project (the "2022 BluEarth Report"), which was adjacent to Aura's Project, was erroneously filed in the AUC proceeding for the BluEarth Yellow Lake Solar Project (Proceeding 25668). The 2022 BluEarth Report was intended to be filed in the proceeding for the relevant BluEarth project (Proceeding 25658) and accordingly was not discoverable by Aura exercising reasonable diligence. Aura explained that it became aware of this on July 28, 2023. Aura argued that the 2022 BluEarth Report was material to the Decision as it provides actual evidence of the effect of a solar project on wildlife in the immediate vicinity.

The AUC determined that the 2022 BluEarth Report could have been discovered during Proceeding 27488 through the exercise of reasonable diligence as required by s 5(1)(b) of *Rule 016: Review of Commission Decisions* ("*Rule 016*"). Aura could have requested the 2022 BluEarth Report from Alberta Environment and Protected Areas ("AEPA") or BluEarth Renewables Inc. during the proceeding. In addition, the AUC determined that the 2022 BluEarth Report did not include new information material to the Decision. The AUC denied a review of the Decision on this ground.

The AUC Made an Error of Fact, or Mixed Fact and Law

Public Interest Test

Aura argued that the AUC did not properly apply the public interest test. Aura claimed that the AUC did not provide reasons demonstrating any balancing of the adverse effects of the Project against the public benefits. Aura stated that the Decision focused primarily on potential adverse effects and failed to address the actual evidence regarding adverse effects, as provided in the Burdett Solar Project 2021 Post-construction Fatality Monitoring Report("2021 BluEarth Report").

Although Aura relied on s 5(1)(a) of *Rule 016* for this ground, Aura primarily characterized this error as an error of law. *Rule 016* does not provide for review of errors of law. Accordingly, Aura's request for a review on this ground was denied.

The review panel determined that the hearing panel's assessment in the Decision that the potential impacts of the Project on the environment are unacceptable and that the Project is not in the public interest was reasonable and based on the record of the original proceeding. The determination does not amount to any error justifying a review.

Adverse Environmental Effects

Aura further argued that the AUC unreasonably assessed the potential adverse environmental effects of the Project. Aura submitted that in the Decision, the AUC attributed excessive weight to minor misalignments with the AEPA *Wildlife Directive for Alberta Solar Energy Projects*. It further argued that the Decision contained a major gap with respect to site-specific data and AEPA's conclusion about the proposed mitigation strategy. Aura stated that decisions that contain such fundamental gaps or that contain an unreasonable chain of analysis are not reasonable and therefore constitute an error of mixed fact and law.

The review panel stated that under *Rule 016*, its role is not to second guess conclusions made in the Decision or provide a second opportunity for parties to reargue the issues in a proceeding. The AUC was satisfied that the hearing panel's assessment of the evidence did not amount to an error of fact or mixed fact and law. The AUC denied a review of the Decision on this ground.

Past Precedent

Aura submitted that, while administrative decision-makers are not bound by their past precedent, decisions that depart from longstanding practices or internal authority must be appropriately justified. Contrary to past precedent, the AUC attributed excessive weight to the AEPA Referral Report's identification of avian mortality risk associated with the Project and to recommended setback infringements. The AUC failed to weigh such adverse effects against the positive effects of the Project, which was an unjustified departure from past precedent. In the AUC's view, this alleged error was an error of law for which no review is available under *Rule 016*.

The AUC denied the request for a review on these grounds since it was not satisfied that Aura appropriately justified or could mitigate the impacts of siting its Project in contravention of the requirements. The review panel reiterated that it should not second guess the hearing panel's assessment absent an error of fact or mixed fact and law. In the review panel's view, no such error has been identified in association with this ground.

Decision Made Without Hearing or Notice

Aura argued that the Decision was made without a hearing and that a review should be permitted on this basis under s 5(1)(d)(i) of *Rule 016*. The AUC stated that, even though the hearing was cancelled, the AUC did conduct a proceeding to assess Aura's application, which consisted of three rounds of information requests. Relevant jurisprudence clearly states that an administrative tribunal, such as the AUC, is the master of its own process. While the AUC did not solicit argument from Aura, it followed a process consistent with the AUC's general practice in facilities proceedings where there are no objections or an objection has been withdrawn. The review panel denied the request for a review on this ground.

***ENMAX Power Corporation 2023-2025 Transmission General Tariff Application and Negotiated Settlement Agreement,* AUC Decision 27581-D01-2023**

Electricity - Rates

<u>Application</u>

ENMAX Power Corporation ("EPC") filed an application with the AUC for approval of its 2023-2025 GTA for the period of January 1, 2023, to December 31, 2025. EPC sought approval of: the forecast revenue requirement for the test period; updated depreciation rates in accordance with the updated depreciation study; a one-time deferred depreciation expense and a one-time placeholder to true up 2022 deferred depreciation expense; the 2023 opening rate base balance; forecast capital additions and rate base for the test period; the methodologies used to allocate common operations costs; continuation of the previously approved transmission deferral accounts; and disposition of the previously approved transmission deferral account balances.

After filing the application, EPC reached a negotiated settlement agreement ("NSA") with the intervening parties and requested an approval of the NSA. EPC and the intervenors subsequently amended the NSA to address the ongoing investigation that commenced after the original NSA was reached. The investigation was initialed by the AUC's enforcement staff ("Enforcement Staff") in relation to the year-end capitalization of certain EPC distribution and transmission projects.

Decision

The AUC determined that the NSA, as amended, was negotiated under a fair process, resulted in just and reasonable rates and, consequently, was in the public interest. The AUC approved the NSA on an interim basis, subject to the outcome of the Enforcement Staff's investigation. The AUC also: approved the recovery of the enterprise software depreciation expense shortfall through EPC's existing amortization of reserve differences ("ARD") mechanism over a period of approximately five years; directed EPS to recover the depreciation shortfalls through the established ARD mechanism; approved the opening adjustments to the closing balance for the test period; and required EPC to address, as part of EPC Distribution's 2025 annual rate application, whether an adjustment is required to ensure that the changed allocation does not create an over-recovery at the expense of customers.

The AUC directed EPC to file a compliance filing to this decision no later than October 31, 2023, and identify any changes required as a result of the Enforcement Staff's investigation.

Pertinent Issues

Negotiated Settlement Agreement

With respect to the NSP, the AUC noted that all participants in the negotiations were sophisticated parties that represent a cross-section of Alberta residential, small business and farm ratepayers. The AUC was satisfied that the parties had the opportunity to participate meaningfully and that the negotiations were conducted in an open and fair manner. The AUC found that EPC provided adequate notice to parties. The AUC was satisfied that, subject to the outcome of the investigation and any related enforcement action that may trigger, the negotiated settlement process ("NSP") was fair and that the requirements set out in ss 3, 6(1) and 6(3) of *Rule 018: Rules on Negotiated Settlements* ("*Rule 018*") were met.

Additionally, the AUC considered each element of the NSA and the NSA as a whole, including whether the NSA will be in the public interest from the perspective of ratepayers. In total, the adjustments resulting from the NSA amount to a reduction of $11.57 million to EPC's 2023-2025 revenue requirements for the transmission business, and a reduction of $8.13 million to EPC's 2023 revenue requirement for the distribution business. Parties to the NSA also agreed that the salary escalation for the Canadian Union of Public Employees ("CUPE") employees will be updated at the time of EPC's compliance filing to reflect the actual outcome of the CUPE contract ratification and that the cost of debt will be updated at the time of EPC's compliance filing to reflect the actual cost of debt. Given the adjustments made and the upcoming updates resulting from the NSA, the AUC found that the amending agreement, taken as a whole, is not patently against the public interest or contrary to law. The AUC found that the NSA, as amended, results in rates and terms and conditions that are just and reasonable, as required by s 8 of *Rule 018* and approved the amended NSA on an interim basis.

Depreciation of Shortfall for Account 487.3

The parties were unable to agree in the NSA to EPC's proposal regarding the recovery of depreciation shortfall for Account 487.3 – General Plant, Computer Systems – Enterprise Software. The AUC, therefore, considered this issue.

Utility assets are booked into accounts using the Uniform System of Accounts ("USA") and depreciated in accordance with AUC-approved parameters. EPC previously applied, and the AUC approved, a 10-SQ curve for Account 487.3, and EPC depreciated the assets in that account at a rate of 10 percent. EPC's depreciation expert recommended at the time of the 2013 depreciation study, a 5.1 percent depreciation rate. This resulted in a longer amortization period and a lower depreciation rate than would be typical for a 10-SQ curve. EPC indicated that, while preparing its most recent 2021 depreciation study, their expert recommended to change its policy and start retiring assets in square curve accounts at the end of the approved amortization period (as opposed to retiring assets when they were taken out of service). This proposal would depreciate the assets in Account 487.3 at a rate of 10 percent, consistent with the 10-SQ curve parameters, rather than at a rate of 5.1 percent. EPC indicated that it accepted this recommendation and formally implemented this policy in 2021, which meant that the depreciation in this account will be accelerated relative to the previous rate. EPC's position was that the variance in this account was not the result of an error or misapplication of depreciation rates, but rather, that it arose in the normal course because of the application of a depreciation rate consistent with a policy that was approved by the AUC. The interveners opposed EPC's proposal.

The AUC emphasized that, in the 2013 depreciation study, it approved depreciation parameters, including estimated service lives, Iowa curves, and where applicable, net salvage percentages. The AUC did not approve the resulting depreciation rates. In the AUC's view, EPC's evidence generally supports EPC's recovery of the capital costs associated with Account 487.3. This is because the variance results from EPC's policy for retiring assets when they are physically taken out of service. It was also acknowledged that EPC relied upon the advice of its experienced depreciation expert, both in implementing the asset retirement policy and the depreciation rate. The AUC held that, to deny EPC recovery of the $18.5 million shortfall in the unique circumstances of this case would not afford EPC the reasonable opportunity to recover its capital investments under s 122(1)(a)(i) of the *Electric Utilities Act*.

The AUC emphasized that EPC's proposed recovery in this case is distinguishable from the facts underlying a recent decision, where the AUC denied ATCO Electric Ltd.'s ("AE") proposed one-time $7.5 million adjustment to its depreciation expense to correct an AE accounting error (Decision 27062-D01-2023). AE had recorded the assets into the incorrect account and had opportunities to identify its error, including when the AUC specifically directed AE to confirm that its then calculated accumulated depreciation balances for the assets in question were accurate. On the other hand, the AUC found that EPC supported its contention that the basis for the variation in depreciation rates is at least partly attributable to an AUC-approved EPC policy. The AUC therefore found that the depreciation rate to Account 478.3 between 2014 and 2022 was not an error and was, therefore, recoverable. Turning to how EPC should recover the variance associated with Account 487.3, the AUC held that the approved ARD mechanism is the appropriate mechanism for recovery.

Accelerated Collection of Deferred Depreciation Expense

EPC requested an "accelerated collection of the deferred depreciation expense" from the years 2021 and 2022 through one-time true-ups of $3.4 million in 2023 and $5.0 million (a placeholder true-up amount) in 2024, rather than using the ARD mechanism, which would recover these amounts over the remaining life of the asset. This issue arose because the AUC denied a depreciation expense claimed by EPC in its last GTA. EPC applied to collect the depreciation amounts from the 2021-2022 capital additions through two lump-sum true-ups, one in each of 2023 and 2024. EPC argued that collecting the amounts as quickly as reasonably possible would mitigate intergenerational inequity concerns and would avoid administrative complexity.

The AUC was not persuaded there are intergenerational concerns of any significance triggered in the assessment of this issue. The AUC considered the previous decision and found that the panel contemplated at that time that the ARD would be an appropriate way for EPC to collect the shortfall in its next tariff application. The shortfalls in question arose as a result of EPC's lack of evidentiary support in its last GTA for its forecast depreciation expenses. With respect to EPC's submissions on the complexity associated with using the ARD to recover the amounts in question, the AUC held that rather than complicating the recovery, the use of the existing ARD mechanism should simplify EPC's recovery in this case. As such the AUC denied EPC's request and directed recovery via the ARD mechanism.

Adjustments to Closing Balance in Previous Years' Closing Balances

EPC's common costs are costs incurred internally and attributable to both EPC Transmission and EPC Distribution. These common costs are allocated to the appropriate business unit, using a common cost allocation methodology. Generally, operating costs that can be directly assigned to a business unit are charged to the relevant business unit. Costs that cannot be directly assigned are allocated, to the extent possible, using an allocator consistent with cost causation. If a cost cannot be directly assigned or allocated based on cost causation, a universal allocator is used. This allocation is based on the forecast test period ratio, rounded to whole numbers. For the 2023 to 2025 test period, EPC updated the capital asset allocator ratio, agreed to by all parties in the NSA. Based on its revised allocations, EPC made opening adjustments in its supporting schedules to previous years' closing balances for the 2021 test period compliance filing, the 2023 forecast, and the 2025 forecast, for the transmission allocated general property, plant and equipment accounts and the corresponding accumulated depreciation accounts.

The AUC was persuaded that the methodology behind the previous years' closing balance adjustments do not result in retroactive ratemaking nor in incorrect forecasting of depreciation and return in the revenue requirement. The AUC was satisfied that the changes proposed by EPC would only impact customer rates on a prospective basis. Also, the depreciation, interest and return for the test years should be based on the value of the assets calculated using the new allocation ratio to properly reflect how the assets are being used. If EPC did not adjust the opening balances, its depreciation, interest and return in the test years would not properly reflect how these assets were being used during that test period, which in turn would result in an incorrect tariff to both EPC Transmission and EPC Distribution. As a result, the AUC approved the opening adjustments to previous years' closing balances for the 2021 test period compliance filing, the 2023 forecast, and the opening adjustment to the 2025 forecast.

***Market Surveillance Administrator Application for Approval of a Settlement Agreement Between the Market Surveillance Administrator, EPCOR Energy Alberta GP Inc. and 1772387 Alberta Ltd,* AUC Decision 28207-D01-2023**

Gas – Markets

<u>Application</u>

The Market Surveillance Administrator ("MSA") applied for approval of a settlement agreement between the MSA, EPCOR Energy Alberta GP Inc. as general partner of EPCOR Energy Alberta Limited Partnership (collectively, "EEA"), and 1772387 Alberta Ltd. ("Encor"), as general partner of 1772387 Alberta Limited Partnership (the "Settlement Agreement").

<u>Decision</u>

The AUC determined that approval of the proposed Settlement Agreement was in the public interest and approved the MSA's application.

<u>Pertinent Issues</u>

The Contravention

The Settlement Agreement was reached after the MSA conducted an investigation regarding a prohibited sharing of customer information for sales purposes that occurred between 2016 and 2021. The parties agreed that this conduct, prohibited by ss 17(2) and 18 of the *Code of Conduct Regulation* ("*COCR*"), gave EEA and Encor an unfair competitive advantage.

Following an investigation, the MSA was satisfied that EEA, on behalf of Encor, used regulated rate option ("RRO") customers' billing histories to determine whether prospective Encor customers were financially eligible for Encor's services. The investigation found that under the service level agreement ("SLA") between EEA and Encor, EEA assessed the financial eligibility of prospective Encor customers, who were asked to consent to a review of their billing history with EEA (an internal credit assessment), for retail electricity services provided by Encor. Where a prospective customer did not consent to an internal credit assessment or one was not available, financial eligibility was assessed based on an external credit score.

By using the internal credit assessment provided by Encor, the cost to EEA passed on to Encor, was lower than the cost of an external credit assessment. This resulted in cost savings for Encor from July 1, 2016, to June 20, 2021. EEA shared the creditworthiness assessment derived from its RRO billing history information with Encor for sales purposes.

EEA and Encor admitted that they contravened s 17(2) of the *COCR*, as well as s 6 of the *Electric Utilities Act*. EEA and Encor admitted to the contraventions and agreed to pay administrative monetary penalties (the "Penalties") and the MSA's investigation costs.

The Settlement Agreement

The Settlement Agreement reflected remedial actions undertaken by both EEA and Encor after receiving the MSA's summary of facts and findings, and included the following terms:

(a) Encor will pay a Penalty of $105,000, including $84,000 as the approximate benefit to Encor due to the contraventions, plus an additional penalty of $21,000;

(b) EEA will pay a Penalty of $21,000; and

(c) EEA and Encor will pay, jointly and severally, costs of the investigation to the MSA of $20,000.

The AUC considered the Settlement Agreement using the public interest test. The AUC was satisfied that the proposed Penalties are reasonable, considering the seriousness of the contraventions and the mitigating actions identified by the MSA. The

AUC was further satisfied that the proposed payment by EEA and Encor to the MSA for the costs of the investigation is appropriate. The AUC determined that the Penalties achieve the goals of specific and general deterrence.

***Strathcona County Amended and Restated Water Supply Agreement with Highway 14 Regional Water Services Commission,* AUC Decision 28436-D01-2023**
Water – Rates

Application

Strathcona County ("Strathcona") applied for approval of its amended and restated water supply agreement (the "Agreement") with the Highway 14 Regional Water Services Commission ("HRWSC").

Decision

The AUC approved the Agreement regulating the supply of potable water by Strathcona to HRWSC.

Pertinent Issues

The original water supply agreement, approved by the AUC in Decision 2012-183 and implemented on January 1, 2012 (the "2012 Agreement"), was set to expire on January 1, 2037. Strathcona entered into a water supply agreement with EPCOR Water Services Inc. ("EPCOR Agreement") in May 2018, pursuant to which Strathcona receives potable water.

Strathcona desired to sell water to the HRWSC under terms that aligned with its EPCOR Agreement, and the HRWSC wished to continue to purchase water from Strathcona. Accordingly, Strathcona and the HRWSC agreed to amend and restate the 2012 Agreement to align with the terms and conditions of the EPCOR Agreement.

The Agreement provided that Strathcona will sell and deliver water to the HRWSC. The proposed term of the agreement remains 25 years, from the original effective date of January 1, 2012. The amended and restated terms and conditions became effective April 18, 2023, and the expiration date was unchanged.

***TransAlta Corporation, as Manager of the TransAlta Generation Partnership Application Concerning Arbitration Award for AltaLink Management Ltd. to Perform its Obligations Under the Operations and Maintenance Agreement,* AUC Decision 28467-D01-2023**
Electricity - Markets

Application

TransAlta Corporation ("TransAlta") submitted to the AUC that the interim order issued in Decision 27168-D01-2023, regarding an operations and maintenance agreement (the "O&M Agreement") reached between TransAlta and AltaLink Management Ltd. ("AML") was no longer needed. TransAlta and AML entered into the O&M Agreement regarding services provided by AML in connection with the assets sold by TransAlta to AML in 2001.

Decision

The AUC rescinded the interim order in Decision 27168-D01-2022 directing AML to continue to perform its obligations set out in the O&M Agreement.

Pertinent Issues

In 2001, TransAlta sold the entirety of its transmission business and assets to AML, apart from certain assets located on 13 First Nations lands in areas south of Edmonton (the "Withheld Assets"). The Withheld Assets are still owned by TransAlta. TransAlta and AML entered into the O&M Agreement, wherein AML has performed services in connection with TransAlta's operation of the Withheld Assets.

In 2020, AML provided a notice of termination to TransAlta, indicating it would cease providing the services at the end of the initial term of the O&M Agreement. Following a dispute concerning the termination, TransAlta commenced arbitration. In Decision 27168-D01-2022, the AUC granted TransAlta an interim order directing AlML to continue to perform its obligations set out in the O&M Agreement until the outcome of arbitration was determined.

The arbitration tribunal concluded that the O&M Agreement is perpetual and that it does not contain an implied term allowing for termination on reasonable notice by AML at the end of the initial term or any renewal term thereof. Accordingly, the O&M Agreement remained in effect. With the arbitration panel's determination, the AUC's interim order was no longer required.

CANADA ENERGY REGULATOR

NorthRiver Midstream NEBC Connector GP Inc., **CER Report OH-001-2022**
Natural Gas Liquids - Facilities

Application

NorthRiver Midstream NEBC Connector GP Inc. ("NorthRiver"), a wholly owned subsidiary of NorthRiver Midstream Inc., applied for authorization to construct and operate the NEBC Connector Project (the "Project"). The Project consisted of two parallel 215-kilometer ("km") small-diameter pipelines from the existing Highway Liquids Hub ("Highway Hub") approximately 25 km northwest of Wonowon, British Columbia ("BC") to a riser site in the Gordondale area of Alberta, approximately 19 km east of the BC/Alberta border. Approximately 195 km or 91 percent of the proposed route parallels existing linear disturbances. The pipelines will transport natural gas liquids ("NGL" or "C3+") and condensate.

Decision

Recommendation under s 183 of the CER Act

The CER found the Project is and will be required by the present and future public convenience and necessity, and recommended that the Governor in Council ("GIC") approve the Project and direct the issuance of a certificate under section 186 of the *CER Act*, authorizing the construction and operation of the Project.

Exemption from CER Act s 213 Requirements (Leave to Open)

The CER denied NorthRiver's request for exemption from the requirement to seek leave to open for its proposed pump station and storage capacity additions at the Highway Hub.

Exemption from CER Act s 214(1) requirements

The CER exempted NorthRiver, contingent upon a certificate being issued, from the requirements of ss 198(c), 198(d) and 199 of the *CER Act* with respect to: temporary infrastructure required for construction of the pipelines; right of way ("ROW") preparation activities (subject to some excluded lands); and installation of pump station and storage capacity within the boundaries of the existing Highway Hub footprint.

Method of Regulation

Regarding financial regulation, the CER found it appropriate to regulate NorthRiver as a Group 2 company, which regulates the traffic, tolls, and tariffs of such companies on a complaint basis.

Pertinent Issues

The Project's purpose is to meet a need for market access for existing and anticipated growth of volumes of NGLs and condensate from the Montney Play ("Montney") in the Western Canadian Sedimentary Basin. It will provide an alternative transportation option for northeast BC producers, fostering competition and increasing shipper choice.

Context

The CER noted the unique context of this Project, particularly the implications of the decision in *Yahey v British Columbia*, 2021 BCSC 1287 ("*Yahey*"). In the *Yahey* decision, the Supreme Court of British Columbia made four declarations relating to the infringement of Blueberry River First Nations' ("BRFN") treaty rights due to the cumulative impacts of industrial development. The Project traverses the BRFN's claim area, which was the area at issue in the *Yahey* decision.

In response to *Yahey*, NorthRiver's Project application acknowledged the existence of significant adverse cumulative effects. In particular, NorthRiver acknowledged the effects on wildlife and wildlife habitat, fish and fish habitat, and traditional land and resource use ("TLRU"). NorthRiver made the conservative assumption that all Indigenous Peoples asserting rights under s 35 of the *Constitution Act, 1982* are similarly affected.

The CER noted that its hearing process allowed for meaningful consultation with Indigenous Peoples that supports several key objectives of the *United Nations Declaration on the Rights of Indigenous Peoples* ("*UN Declaration*") focused on the participation of Indigenous Peoples. The CER made its recommendation and decisions on this Project with consideration for the Government of Canada and CER's commitments to Reconciliation and the implementation of the *UN Declaration*. At all stages of the hearing process and in undertaking its assessment of the Project, the CER noted that it was guided by the need to uphold the honour of the Crown and advance Reconciliation.

Project Economics and Financial Matters

The CER found that the Project is economically feasible and likely to be used at a reasonable level over its economic life, even when taking into consideration reasonable expectations about the potential impacts of current climate change laws, policies, and regulations. The CER found that NorthRiver adequately accounted for risks associated with uncertainties posed by any scenario in which Canada achieves net-zero greenhouse gas emissions by 2050, in its analysis of the Project's economic feasibility. The CER determined that the Project will benefit Canadian oil and gas producers by enhancing shipper choice, improving overall transportation efficiency and safety and decreasing transportation costs and third-party impacts.

Pipeline Design, Construction and Operation

The CER found the Project's general design and material specifications to be appropriate for its intended use and found the description of NorthRiver's integrated management system adequate. The CER was satisfied with NorthRiver's emergency response planning, emphasizing that processes, procedures and communication protocols were established for its Emergency Response Plans.

Land Matters

The CER found that, on balance, the applied-for route corridor is appropriate, reasonably minimizing impacts on the environment, Indigenous Peoples, landowners, and land users, while also providing the most efficient design for construction and operations. In response to expressed concerns from one intervener, the CER recognized that NorthRiver did not meet all the route selection criteria for the portion of the route crossing this intervener land but noted that feedback from potentially affected landowners is one of the routing criteria used. The CER was convinced that the Project route was responsive to feedback from landowners. In making the recommendation for the Project, the CER made no findings about the best possible detailed route of the pipeline on the lands of this intervener leaving the issue open for a potential detailed route hearing.

Matters Related to Indigenous Peoples

The CER found that NorthRiver adequately designed and implemented engagement activities with Indigenous Peoples for the Project. NorthRiver's engagement program was designed to continue for the life-cycle of the Project, and the CER expressed an expectation that NorthRiver will follow through on its engagement obligations and commitments accordingly.

The Crown Consultation Coordinator ("CCC"), which is part of the CER, confirmed that it intends to rely on the CER's assessment process for this Project, to the extent possible, to meet the Crown's duty to consult. The CCC was involved in early engagement, actively participated in the hearing, and conducted concurrent consultation activities outside of the hearing. Based on its consultation with Indigenous communities on the Crown List, the CCC filed several Crown submissions on the hearing record.

During the hearing, the CER received Indigenous knowledge directly, through multiple methods, which shaped the CER's findings, analysis and recommended conditions issued for the Project.

The total cumulative effects for the TLRU are high, as they were assumed to be significant by NorthRiver in recognition of *Yahey*. However, NorthRiver included a plan to offset the impacts of the Project. As a result of the offset plan, the CER found that the potential adverse effects of the Project on the rights of Indigenous Peoples would be of a medium degree of severity.

The CER found that Indigenous Peoples monitoring the Project is a valuable and meaningful opportunity for the sharing and incorporation of Indigenous knowledge in the planning, pre-construction, construction, post-construction, and operational life-cycle activities of the Project. The involvement of Indigenous Peoples in monitoring would also be of value in assessing mitigation measures effectiveness, including reclamation. In addition, NorthRiver committed to providing an opportunity for all interested Indigenous communities to participate as monitors during construction. The CER imposed various conditions regarding plans for Indigenous Peoples' participation in construction, post-construction and operations monitoring.

Environmental Effects

The CER recognized the importance of the construction environmental protection plan ("Construction EPP") as a compilation of general and Project-specific mitigation measures for use during Project construction. The CER imposed conditions regarding Construction EPP, operations environmental protection plan ("Operations EPP"), and post-construction environmental monitoring reports to ensure potential adverse effects are effectively mitigated and, where they have not, to adaptively manage deficiencies.

Health, Social and Economic Effects

One landowner intervener raised concerns regarding impacts on agricultural operations, watercourse and wetland areas, groundwater and surface water drainage issues, as well as aerial operations being conducted concurrently with the operations of their airstrip. The CER determined that all issues raised would be mitigated through the implementation of NorthRiver's Construction EPP, as well as its commitment to ongoing engagement with the landowner regarding the proposed construction method in the specific area. The CER acknowledged the information NorthRiver provided during the hearing on how it intends to monitor the socio-economic effects of the Project, including its preliminary Indigenous socio-cultural monitoring plan. The CER imposed several conditions to ensure added transparency.

Cumulative Effects and NorthRiver's Proposed Offset Plan

Indigenous intervenors were unanimous that existing cumulative effects in the area are high. The CER agreed that past and existing development, including forestry, oil and gas, agriculture, and linear developments, such as roads and pipeline corridors, have led to adverse cumulative effects of high significance on wildlife and wildlife habitat, fish and fish habitat, and the TLRU. NorthRiver applied the mitigation hierarchy appropriately in the design and development of the Project and through the modifications it made during the hearing. NorthRiver first avoided effects where feasible through its route selection. NorthRiver then identified opportunities to avoid and reduce effects through mitigation and to restore certain areas along the right-of-way. Where significant adverse effects remained or were assumed, offsetting was presented as mitigation.

The CER acknowledged the evolution from the Preliminary Offset Plan through the Final Offset Plan, submitted throughout this process. Some notable changes to NorthRiver's offset plan included: incorporation of the mandatory BRFN – British Columbia ("BRFN-BC") Restoration Fund contribution; expansion to include contribution to the Treaty 8 Restoration Fund and offsets for all New Disturbance on Crown land in BC and Alberta; and, incorporation of Indigenous-led governance with capacity funding and an increased overall dollar amount. The CER, considering all submissions, concluded that the offset plan should include the following components:

- NorthRiver must contribute to the BRFN-BC Restoration Fund for New Disturbance in HV1 and priority watershed management basin areas following the BRFN Implementation Agreement.
- NorthRiver must contribute to the Treaty 8 Restoration Fund for New Disturbance within Treaty 8 Enhanced Management Corridors using a similar methodology as the BRFN Implementation Agreement.
- NorthRiver-established Indigenous-led Land Securement Fund based on the remainder of Crown lands in BC and Alberta that meet the definition of New Disturbance and are not directly addressed by Offset Components 1 and 2.

The CER accepted the majority of NorthRiver's Final Offset Plan except for refinements to the Land Securement Fund. Accordingly, the CER imposed conditions regarding the revised Final Offset Plan, BBRFN-BC Restoration Fund Reporting, Treaty 8 Restoration Fund Reporting, and Land Securement Fund Reporting.

Trans Mountain Pipeline ULC TMEP Application Pursuant to Section 211 of the Canadian Energy Regulator Act Segment 5.3 – Pípsell (Jacko Lake), **CER Reasons for Decision A8T7K1**
Gas - Facilities

<u>Application</u>

Trans Mountain Pipeline ULC ("Trans Mountain") applied for approval of a deviation ("Deviation Application") to the approved plan, profile and book of reference ("PPBoR") in respect of certain lands in Segment 5.3 of the Trans Mountain Expansion

Project ("TMEP"). Trans Mountain also requested relief from the requirement to deposit the certified PPBoR before constructing the deviation.

Decision

The CER approved the Deviation Application, including Trans Mountain's requested exemption from the requirement to deposit the PPBoR, and issued Order AO-003-OPL-003-2020 reflecting this approval.

Pertinent Issues

The route subject to this proceeding (the "2023 Revised Route") concerns 1.3 kilometers ("km") of the TMEP pipeline in the Pípsell Area. The deviation remains entirely within the approved pipeline corridor on privately owned land. Trans Mountain submitted that the deviation is required to accommodate a change in construction methodology due to significant technical challenges encountered with micro-tunneling along a portion of the previously approved route in that section. The construction method will be changed from micro-tunneling to a combination of horizontal directional drilling ("HDD") and conventional open trench.

Engagement

The landowners impacted by the deviation confirmed that they had no concerns with the 2023 Revised Route. The deviation is located within the traditional territory of the Stk'emlúpsemc te Secwépemc Nation ("SSN"). The SSN expressed concerns regarding deviating from entirely trenchless construction methods in the Pípsell Corridor.

Trans Mountain stated that the proposed mitigation measures to avoid or minimize potential environmental, traditional land use, and cultural impacts, as well as its proposed combination of HDD and conventional open trench construction, would reasonably avoid or minimize impacts on the lands subject to the 2023 Revised Route. Trans Mountain submitted that approximately 80 percent of construction within the approximately 4.2-km-long Pípsell Corridor would be completed using trenchless construction, minimizing disturbance of the ground and the traditional territory of the SSN.

Relief From the Requirement to Deposit the Certified PPBoR Before Construction

To avoid further construction delays on the TMEP, Trans Mountain requested relief from the requirement in s 211 of the *Canadian Energy Regulator Act* ("*CER Act*") to register in advance the certified PPBoR since the center line of the deviation did not, at any point, extend more than 60 meters from the route approved in the PPBoR.

CER Findings

In approving the application, the CER considered several factors, including the impact on the rights and interests of Indigenous Peoples, the environmental, socio-economic and engineering factors and, the engagement and impact mitigation.

The Pípsell Area holds profound cultural and spiritual significance to SSN and Trans Mountain agreed to attempt to construct a 4.2-km segment of the TMEP in this area using micro-tunneling, to minimize surface disturbance. Trans Mountain tried unsuccessfully to overcome the challenges encountered in a 1.3-km section originally identified for micro-tunneling resulting in additional $32 million in costs and extended construction timelines by several months.

The CER was satisfied that any environmental or socio-economic impacts of the deviation will be sufficiently addressed by the environmental and socio-economic mitigation measures identified for the TMEP. The CER noted that the alternative HDD method, applied for by Trans Mountain, is a mitigation measure aimed at reducing surface disturbance.

Based on Trans Mountain's robust engagement efforts and the CER's hearing process, the CER found that the duty to consult with Indigenous Peoples and accommodate their interests was met. The CER also considered its duties and obligations under the *United Nations Declaration on the Rights of Indigenous Peoples Act* and the CER's commitment to Reconciliation and found that any requirements thereunder were adequately addressed. The CER also assessed the effects of the Deviation Application on the rights of Indigenous Peoples in the context of its technical findings and determined that any impacts can be meaningfully addressed, based on the mitigation measures identified in the Deviation Application and through conditions imposed by earlier TMEP regulatory processes.