REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA ENERGY REGULATOR

Regulatory Appeals of the Decision to Issue Declarations Naming Darren O'Brien and Jeffrey Young Pursuant to Section 106 of the Oil and Gas Conservation Act, **Regulatory Appeals 1928568 and 1928569**
Control of Licensee - Time of Failure to Comply with Order - S. 106 Order

In this decision the AER revoked the declarations made under section 106(1) of the *Oil and Gas Conservation Act* ("*OGCA*") naming Darren O'Brien and Jeffrey Young (collectively, "the Requesters"), former directors of Trident Exploration (Alberta) Corp. ("Trident Alberta") and Trident Exploration (WX) Corp. ("Trident WX") (collectively, "Trident").

<u>Background and History</u>

The Requesters served as directors of Trident from September 6, 2016 to April 30, 2019. Mr. O'Brien also served as Trident's president from January to April 30, 2019.

Trident held well, pipeline, and facilities licences issued by the AER. According to the Requesters, Trident produced mainly shallow, dry natural gas from coalbeds and had ownership interest in 4700 wells and ownership of 29 gas plants. The Requesters stated that, in February 2019, 2700 of Trident's wells were still producing, 22 of its gas plants were in operation, and Trident's production was 85 million cubic feet of oil equivalent per day.

The Requesters said that they were appointed directors of Trident following the recapitalization of Trident because of their involvement with Origami Capital Partners, LLC, which had, by the end of 2016, invested over $60 million in Trident with the goal to improve operations.

On April 29, 2019, the AER's Compliance and Liability Management Branch ("CLM") issued an order (the "Order") to Trident:

(a) restricting its eligibility for AER licences and requiring it to submit an updated Schedule 1 pursuant to Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals by June 1, 2019;

(b) requiring that, by June 14, 2019, Trident either apply to transfer its well, facility, and pipeline licences to a person, or persons, eligible to hold AER licences; post a security deposit of $245,714,822.00 for the total deemed liabilities of Trident Alberta and $13,294,700.50 for the total deemed liabilities of Trident WX; or submit a compliance plan to the AER for approval; and

(c) requiring that, by June 14, 2019, Trident update the working interest participant records associated with its licences and confirm that all fluids had been removed from its inactive sites.

No evidence was presented in this proceeding demonstrating that before April 29, 2019, Trident's operations caused any risk to the safety of the public, or the environment, or that Trident squandered any resources.

On April 30, 2019, Trident shut in what it perceived to be its highest-risk sites, ceased operations, terminated its staff, and Mr. O'Brien and Mr. Young resigned as Trident's only directors.

On May 2, 2019, the Orphan Well Association filed an application with the Alberta Court of Queen's Bench to appoint a receiver for Trident. On May 3, 2019, the court heard the application, and by order appointed PricewaterhouseCoopers Inc. as receiver.

The receiver's first report indicated that on April 30, 2019, Trident's contractors and field staff shut in all of Trident's facilities, most of their compressor stations, and approximately 700 wells. After April 30, 2019, about 1700 wells continued to flow and accumulate pressure in Trident's pipeline system. The receiver also indicated that following its appointment on May 3, 2019, its primary concerns were to shut in the remaining producing wells and to generate funds for the shut-in work and the receivership.

CLM issued the declarations on October 9, 2019, imposing various restrictions on the Requesters' future activities regulated under the *Oil and Gas Conservation Act* (*"OGCA"*) and the *Pipeline Act*. The declarations and reasons for the decision were signed by Mr. Robert Wadsworth, who was then Vice President of the AER's Closure and Liability Branch (as it was then known).

CLM stated that Trident's cessation of operations occurred without an orderly transition for the care and custody of the assets, leaving wells, facilities, and pipelines in an unsecured state. It further maintained that by ceasing operations and failing to comply with the order, the Requesters exposed the Province of Alberta to end-of-life liabilities of about $259 million. According to CLM, these were aggravating factors it considered in issuing the declarations.

<u>Requests for Regulatory Appeal</u>

The Requesters filed requests for regulatory appeal of the declarations under Part 2, Division 3, of the *Responsible Energy Development Act* ("*REDA*") and Part 3 of the *Alberta Energy Regulator Rules of Practice*, which were granted on May 4, 2020.

OGCA

Section 106(1) sets out the substantive elements that must be met to issue a declaration, section 106(2) establishes the process the AER must provide before issuing a declaration, and section 106(3) sets out the actions the AER may take with respect to any entity regulated by the AER that is, in the AER's opinion, directly or indirectly controlled by the person named in a declaration.

Section 106(1) is clear and specific in setting out the elements that must be met to issue a declaration. It requires evidence that an individual named in a declaration was "directly or indirectly in control of the licensee…at the time of the contravention, or failure to comply" with an order. The Panel noted that it could not ignore parts of section 106(1) to fulfil broader purposes as urged by CLM. Therefore, in this decision the Panel had to determine whether the Requesters had direct or indirect control of Trident at the time Trident failed to comply with the order.

Furthermore, the parts of section 106 are to be applied sequentially. The Panel agreed with the Requesters' submissions that section 106(1) must be satisfied before section 106(3) is engaged, and that the broad nature of section 106(3) does not expand or modify the ordinary meaning of section 106(1).

The Panel noted that the purpose of section 106 of the *OGCA* is to ensure compliance and to prevent further noncompliance by any licensee controlled by a named person. A person named in a declaration, and any licensee or approval holder controlled by that person, may be subject to limitations on their participation in the oil and gas industry in Alberta. The parties agreed that section 106 declarations can have significant effects on individuals and their activities. The Panel found that such impact favours applying section 106 in accordance with its ordinary meaning, as argued by the Requesters.

<u>Issues</u>

A valid *OGCA* section 106 declaration must meet the substantive requirements in subsection (1) as follows:

- A licensee, approval holder, or working interest participant has contravened or failed to comply with an order of the AER, or has an outstanding debt to the AER, or to the AER to the account of the orphan fund, in respect of suspension, abandonment, or reclamation costs;
- The person to be named was, in the AER's opinion, in direct or indirect control of the licensee, approval holder, or working interest participant at the time of the contravention, failure to comply, or failure to pay;
- The AER considers it in the public interest to issue the declaration.

In this proceeding, the following facts were not contested by the parties and were established to the AER Panel's satisfaction:

- Trident did not comply with an order of the AER;
- The Requesters were directors of Trident from September 6, 2016, to April 30, 2019. Mr. O'Brien also served as Trident's president from January to April 30, 2019.

The section 106 requirements that remained at issue were:

- whether the Requesters were in direct or indirect control of Trident at the time Trident failed to comply with the order, and
- whether the declarations were in the public interest.

Also, at issue during the hearing was the matter of whether the Requesters had a reasonable apprehension of bias regarding the decision maker, Mr. Robert Wadsworth, who signed the declarations.

Control of Licensee

Section 106 requires evidence that a party named in a declaration was "directly or indirectly in control of the licensee…at the time of the contravention, or failure to comply" with an order.

The Panel found, in accordance with section 108 of the *Alberta Business Corporations Act*, that the Requesters resigned as directors and officers of Trident effective April 30, 2019, after which time they had no direct control of Trident. Further, the Requesters did not have indirect control of Trident after their authority was terminated on May 3, 2019, by appointment of the receiver with authority to take possession and exercise control of Trident's assets and to manage, operate, and carry on Trident's business.

Time of Failure to Comply with the Order

There was no dispute that Trident had not complied with the order when the Requesters resigned as Trident's directors and Trident ceased operations on April 30, 2019. The parties also agreed that the order required Trident to fulfil certain obligations by June 1, 2019, and other obligations by June 14, 2019.

After the Requesters resigned on April 30, 2019, and until the receiver's appointment on May 3, 2019, Trident was in limbo and unable to legally operate. However, the Requesters' resignations did not trigger an immediate presumption of contravention of the order. The Panel noted that the legislature chose to link control of the licensee to the time of contravention or noncompliance as a necessary element of section 106(1) of the *OGCA*. Had the legislature intended otherwise, it could have used language to that effect.

The Panel found that Trident's failure to comply with the order did not occur until June 2, 2019, once the first deadline for compliance lapsed, at which time the Requesters were not in direct or indirect control of Trident.

<u>Conclusion</u>

Each element of *OGCA* section 106(1) must be met to issue a declaration. Failure to satisfy any element means the legal requirements have not been met and a declaration cannot be issued. In the Panel's view, CLM did not err in concluding that Trident failed to comply with an order of the AER. However, CLM failed to establish that the Requesters were in direct or indirect control of Trident at the time of noncompliance. Given that the Panel found that the Requesters were not in control of Trident at the time it failed to comply with the order, the requirements under *OGCA* section 106(1) could not be met. The AER revoked the decision to issue the declarations naming the Requesters.

ALBERTA UTILITIES COMMISSION

Proposed Amendments to AUC Rule 016, **AUC Bulletin 2021-02**

As part of the effort to implement process efficiencies identified in the Report of the AUC Procedures and Process Review Committee, the AUC proposes amendments to Rule 016: *Review of Commission Decisions*.

Proposed Changes

In consideration of the Supreme Court of Canada's decision in *Canada (Minister of Citizenship and Immigration) v Vavilov*, which altered the standard of review applicable to many AUC decisions, the AUC proposed changes to Rule 016 that would:

- Limit review applications to errors of fact, or mixed fact and law where the legal principle is not readily extricable.
- Change the filing deadline for review and variance applications to 30 days after the original decision is issued.
- Introduce page limits for applications and reply submissions.

Where the outcome of a review application was clear on its face, the AUC proposes to proceed directly to a decision without seeking submissions from other parties. In applications where submissions from other parties are warranted, the AUC will no longer require statements of intent to participate, and immediately request submissions from the parties.

The AUC's review of Rule 016 will consist of a stakeholder consultation involving a written process.

Amendments to AUC Rule 019, **AUC Bulletin 2021-03**

The AUC approved amendments to Rule 019: *Specified Penalties for Contravention of ISO Rules*. The changes are effective as of March 1, 2021.

On December 17, 2020, the AUC initiated a rule-review process in which it sought feedback from stakeholders on changes to Rule 019 as proposed by the Market Surveillance Administrator ("MSA"). The proposed changes involved having Rule 019 apply to all independent system operator ("ISO") rules, collapsing the current three categories of contraventions into one category, and using the penalty escalation currently found in the Category 1 table to determine the penalty amount for subsequent contraventions of the same ISO rule.

Most stakeholders who provided comments supported the proposed changes. However, some stakeholders believed that treating all ISO rule contraventions with the same severity and risk may not provide the proper guidance regarding compliance.

While the AUC approved the amendments as proposed by the MSA, the AUC sees merit in exploring with market participants and other stakeholders the need to conduct a comprehensive review of Rule 019. Given the regulatory schedule, the AUC will not commence this review until the fourth quarter to 2021.

1195714 Alberta Ltd. Empress Industrial System Designation, Power Plant, and Interconnection Project, **AUC Decision 26123-D01-2021**

Facilities - Industrial System Designation

In this decision, the AUC approved applications from 1195714 Alberta Ltd., a subsidiary of Pembina Pipeline Corporation ("Pembina"), to construct and operate a new cogeneration power plant, to connect the cogeneration power plant to the Alberta Interconnected Electric System ("AIES") and for an industrial system designation ("ISD") that included all electrical facilities at the existing Empress Natural Gas Liquids Straddle Plant (the "Empress Plant").

Application for new Cogeneration Power Plant

Application

Pembina applied on behalf of 1195714 Alberta Ltd. for a cogeneration power plant that would consist of a natural gas-fuelled turbine generator and a heat recovery unit to capture thermal energy from the turbine's exhaust gas. Pembina stated that the power plant would provide 45 megawatt ("MW") of electricity and 40 MW of thermal energy for use by the Empress Plant's extraction and fractionation operations. The proposed cogeneration power plant would be powered by fuel gas blended with regeneration gas from on-site propane and butane treating. The power plant would be located within the existing boundaries of the Empress Plant. Pembina expected the power plant to be in service in January 2023.

Pembina provided a noise impact assessment ("NIA") for the proposed cogeneration power plant. The NIA predicted that three theoretical receptor locations would experience cumulative sound levels between 0.1 dBA and 1.2 dBA higher than the nighttime permissible sound level of 40 dBA. The closest actual residence identified in the NIA was 2.0 kilometres away from the Empress NGL Straddle Plant's fence line. The NIA attributed the dominant noise source at the three theoretical receptor locations that would experience exceedances of the nighttime PSL to nearby facilities owned by Plains Midstream Canada ULC.

Stantec Consulting Ltd. ("Stantec") conducted an air quality assessment to evaluate the effects of the addition of the proposed cogeneration power plant on ambient air quality. The assessment determined that maximum ambient nitrogen dioxide (NO_2) and sulphur dioxide (SO2) concentrations associated with the Empress NGL Straddle Plant would be below the Alberta Ambient Air Quality Objectives ("AAAQO").

AUC Findings

The AUC noted that while the NIA identified cumulative sound levels at certain theoretical receptor locations to be above the nighttime PSL of 40 dBA, these predicted exceedances were largely attributed to the nearby Plains Midstream facilities.

The AUC was prepared to approve the project notwithstanding the predicted exceedances, given that: (a) the Plains Midstream facilities were the dominant noise sources in the area; (b) Pembina had committed to implementing mitigation measures to limit further sound level increases; and (c) there were no residences within 1.5 kilometres of the Empress Plant. The AUC found the cogeneration plant to be in the public interest.

Connection Application

Pembina applied on behalf of 1195714 Alberta Ltd. to connect the proposed cogeneration power plant, located within the Empress Plant site, to the AIES to facilitate the export of excess electricity.

Pembina stated that it filed a system access service request ("SASR") with the Alberta Electric System Operator ("AESO") on May 13, 2019, seeking a "Behind the Fence" addition of the proposed cogeneration power plant. Pembina stated that there would be no change to the existing demand transmission service ("DTS") contract for the Empress Plant, and that it has requested a new supply transmission service ("STS") contract.

The AUC found that the connection application had met the requirements set out in Rule 007 and that the approval was in the public interest.

ISD Application

Legislative Scheme

The AUC stated that read broadly, Section 4 of the *Hydro and Electric Energy Act* ("*HEEA*") permits an ISD where the development of on-site generation is a component of an efficient, highly integrated industrial process where on-site generation represents the most economical source of generation for on-site operations.

AUC Findings

The AUC accepted that Pembina, on behalf of 1195714 Alberta Ltd. sought an ISD because the use of its own internal supply of electricity would be the most economical source of generation to meet its integrated industrial processes. The AUC was also satisfied that Pembina's proposal to export excess electricity in the case of a load rejection event would facilitate the efficient exchange, with the interconnected electric system, of electric energy beyond Pembina's own requirements in very limited circumstances.

The AUC was satisfied that Pembina was not seeking an ISD to avoid system costs and the designation would not result in an uneconomic bypass. The AUC noted that Pembina would continue to import electricity from the AIES via an existing DTS contract to satisfy the Empress Plant's load requirement. Further, Pembina had applied for an STS contract with the AESO. Pembina would pay tariffs for its exchange of electricity with the AIES in accordance with its DTS contract and applied for STS contract.

The AUC found that Subsection 4(3)(c) of the *HEEA* had not been met as there was not common ownership of all the components of the industrial operations. While 1195714 Alberta Ltd. had sole ownership of the proposed cogeneration power plant and the Empress NGL Fractionation Facility, AltaGas Extraction and Transmission Limited Partnership has a minor ownership interest in in the Empress NGL Extraction Facility and did not object to the application for an ISD. The AUC was satisfied that all the separately owned components and all of the industrial operations are components of an integrated industrial process. Consequently, it found that the proposed ISD met the requirements of Subsection 4(4) of the *HEEA.*

The AUC found that granting the ISD would, as required, be consistent with the principles set out in Subsection 4(2) of the *HEEA* and the criteria found in Subsection 4(3) of the *HEEA.*

<u>Decision</u>

Pursuant to sections 11 and 19 of the *HEEA,* the AUC approved the application for a new 45-MW cogeneration power plant

Pursuant to Section 18 of the *HEEA,* the AUC approved the application to connect the cogeneration power plant to the AIES.

Pursuant to Section 4 of the *HEEA* and sections 2(1)(d) and 117 of the *Electric Utilities Act*, the AUC approved the application for an ISD.

Alberta Electric System Operator Needs Identification Document Application and ATCO Electric Ltd. Facility Applications Thickwood to Voyageur Transmission Project, **AUC Decision 26035-D01-2021**
Facilities - Needs Identification Document

In this decision, the AUC approved a needs identification document ("NID") application from the Alberta Electric System Operator ("AESO") and a facility application from ATCO Electric Ltd. ("AE") for the Thickwood to Voyageur Transmission Project (the "Project").

<u>Discussion</u>

Needs Identification Document

The AESO had received a system access service ("SAS") request from Suncor Energy Inc. ("Suncor") to connect the approved 800-megawatt ("MW") Suncor Base Plant Cogeneration Facility to the Alberta Interconnected Electric System ("AIES").

The AESO proposed that the need could be met by constructing a new double-circuit, 240-kV transmission line from Suncor's Voyageur Substation to ATCO Electric ("AE")'s Thickwood Hills Substation and by altering Thickwood Hills Substation by adding three 240-kV breakers. The AESO also proposed to upgrade Suncor's existing 240-kV transmission lines by replacing the existing conductors with higher capacity conductors. The NID also proposed minor alterations to AltaLink Management Ltd. and Alberta PowerLine General Partner Ltd. facilities.

AE was directed by the AESO to file a facility application with the AUC for facilities to meet the identified need and to assist the AESO in conducting a participant involvement program for its NID application

Facility Applications

In its facility applications, AE requested approvals to meet the NID.

The environmental evaluation conducted by AE concluded that, based on the design of the Project and implementation of proposed mitigation measures, residual effects of the Project were not expected to be significant. AE further conducted a participant involvement program in accordance with Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*.

AE estimated the cost of the Project to be $101.3 million, with all costs allocated to Suncor. The target in-service date for the Project is July 1, 2022.

AUC Findings

The AUC was satisfied that the application filed by AE included all required information and had met all applicable rules. The AUC found that the proposed Project was in the public interest and approved the facility application, pursuant to sections 14, 15, 18 and 19 of the *Hydro and Electric Energy Act*.

The AUC was satisfied that the AESO's NID application met the requirements set out in the *Electric Utilities Act, Transmission Regulation* and Rule 007. Accordingly, the NID application was approved.

***AMAR Developments Ltd. Final Water Rates for Cambridge Park Estates*, AUC Decision 25519-D02-2021**
Rates - Water Rates

In this decision, the AUC considered the complaint by the Cambridge Park Phase 1 and 2 Home Owners Association ("HOA") against AMAR Developments Ltd. ("AMAR") and the related application by AMAR for approval of the proposed rates for 2020, 2021 and 2022. The AUC approved, on a final basis, rates that were in effect from May 1, 2020, interim rates approved in Decision 25519-D01-2020,1 and AMAR's forecast rates for January and February 2021.

Introduction

This was AMAR's first time applying to the AUC for approval of its water rates. AMAR operates "a system, works, plant, equipment or service" for the delivery or furnishing of water to customers. The AUC therefore determined that AMAR meets the definition of a public utility provided in the *Public Utilities Act* ("*PUA*"). The AUC noted that its authority to address the customer complaint and set AMAR's rates began at the time of the HOA complaint. Given that the evidence provided by the parties was based on monthly intervals and because May was the first complete month for which evidence was provided, the AUC considered rates from May 1, 2020 onwards.

Revenue Requirement

Cambridge Park is a residential subdivision in Rocky View County, located east of the City of Calgary. The developer, AMAR, had completed the first three development phases, consisting of 181 homes. At the time of this application the water supply for Cambridge Park was provided by two water wells, each with permanent diversion licences. Each well had an annual diversion limit of 48,000 m^3.

On July 14, 2020, AMAR received approval for the Phase 4 development. This approval was conditioned on phases 1 to 4 of Cambridge Park being connected to the Rocky View County regional water system. Once the pipeline connecting Cambridge Park to the regional water system is complete, the water wells at Cambridge Park would be abandoned, and Rocky View County would take over operations and the provision of potable water to Cambridge Park residents. At that time, new water rates would be implemented pursuant to Rocky View County's bylaws. AMAR stated that the pipeline is to be in place by the end of 2021 and noted the completion data for final designs and tender documentation was set for June 2021.

AMAR forecasted operational costs for 2020, 2021 and 2022 as $373,205, $409,600 and $414,519, respectively. AMAR submitted a forecast of customers and average monthly customer usage. For 2020 it had forecast 186 customers and a usage of 29.8 m^3, for 2021 it forecast 201 customers and a usage of 30.4 m^3 and for 2022 the forecast showed 208 customers and an average use of 27.2 m^3.

The AUC reviewed AMAR's calculations associated with hauled water volumes and costs. It further considered issues raised by participants regarding the amounts used and the methods of calculation. The AUC determined that AMAR's calculations were reasonable and that AMAR had acted in the best interest of its customers. The AUC accepted AMAR's forecast water hauling costs in 2020 and 2021, of $137,139 and $189,000, respectively.

With regard to general and administrative expenses, the AUC approved the insurance amounts, professional fees, and office management and administrative expenses for 2020 and 2021. With regard to an administrator position, the AUC was not persuaded by the evidence submitted by AMAR, that the $2,000 per month expense is warranted for the administrator position, and reduced the forecast amount associated with this position by 50 per cent and approved administrator expenses of $6,000 and $12,000 for 2020 and 2021, respectively.

Approved Revenue Requirement

The AUC determined the amounts proposed by AMAR were reasonable and approved the amounts of $367,205 and $397,600 to be included in the 2020 and 2021 revenue requirement, respectively, for the water treatment system. The AUC indicated it would pro-rate expenses associated with water testing, maintenance and repairs, water hauling, chemicals, water well and professional fees for 2020 equally over the year, as opposed to only from May to December 2020 as indicated by AMAR, to maintain fairness to both customers and the utility.

The AUC would consider the monthly revenue requirement amount of $30,600 in determining rates.

Rates

AMAR proposed the following rates:

Period	Fixed Rate	Variable charge	Supplemental variable charge (> 1.1 m^3/day average over month)
2020	20.00 $/month	5.000 $/$m^3$	14.50 $/$m^3$
2021	20.00 $/month	4.650 $/$m^3$	14.50 $/$m^3$
2022	20.00 $/month	4.650 $/$m^3$	14.50 $/$m^3$

Billing Determinants

The AUC approved the billing determinants proposed by AMAR.

Approved Rates

The AUC approved the fixed charge of $ 20.00. Regarding the majority of AMAR's revenue requirement being recovered through the variable charge of its proposed rates, the AUC noted that this rate structure could create long term concerns. However, because the proposed pipeline and water system would likely be turned over to Rocky View County in late 2021, the AUC found that this structure would not result in long term concerns.

Regarding AMAR's variable charge of 14.50 $/m^3$ s, the AUC noted this amount had been approved as part of AMAR's interim rates in July 2020. It noted that there was no direct relationship between revenue from the supplemental variable charge and hauled water expenses and, further, agreed with AMAR that this charge served to encourage water conservation throughout the year. The AUC was satisfied with AMAR's proposed rate design.

The AUC noted that the forecast revenue is greater than the proposed revenue requirement, and AMAR referred to the difference as net revenue. According to section 90(3) of the *Public Utilities Act*, an owner of a public utility may earn a fair return on the rate base. However, AMAR did not identify this as a revenue requirement item subject to testing, and potential approval by the AUC. As previously noted, the AUC has accepted AMAR's position that the proposed rates are only recovering operating costs.

The AUC addressed this issue through the management fee. The management fee, based on information provided by AMAR, would have been 6.4 per cent and 5.4 per cent of the proposed 2020 and 2021 revenue requirement, respectively. No information was provided to support these amounts. The AUC found that the potential of missing revenue, and the needs of the utility should be balanced out with the customers' desire to minimize fees. Therefore, the AUC, in exercising its discretion and judgement, approved a management fee of 5.0 per cent.

To reduce regulatory lag and burden, the AUC approved all rates and volumes charged by AMAR commencing May 1, 2020, on a final basis. The AUC also approved AMAR's fixed rate and supplemental rate for 2021 and will adjust AMAR's 2021 variable charges on a go-forward basis.

The AUC found that, based on rates charged in 2020, AMAR had over-collected rates in the amount of $57,542. The AUC provided details of the reconciliation in Appendix 2 and approved water rates consisting of a fixed rate of $ 20.00/month, a variable charge of $3.495/m^3 and a supplemental variable charge of $14.50/m^3, for greater than 1.1 m^3/day average usage over the month, as of March 1, 2021. $45,302 was to be refunded to customers.

<u>2022 Rates</u>

The AUC noted that AMAR's rates for 2022 mirrored the proposed rates for 2021. Based on the information provided by AMAR, the AUC anticipated that the pipeline connecting the Rocky View County regional water system with Cambridge Park would be completed prior to the end of 2021, at which time Rocky View County would take over the responsibility to provide water and the billing for water services.

However, to provide for the event that Rocky View County does not assume operations prior to 2022, the AUC approved rates for AMAR commencing January 1, 2022, consisting of a fixed charge of $20.00/month, a variable charge of $4.234/m^3 and a supplemental variable charge of $14.50/m^3, for greater than 1.1 m^3/day average usage over the month.

***Aura Power Renewables Fox Coulee Solar Project Amendment*, AUC Decision 25296-D01-2021**
Facilities - Solar Plant

In this decision, the AUC approved the application from Aura Power Renewables Ltd. ("Aura") to amend the previously approved 75-megawatt ("MW") solar plant designated as the Fox Coulee Solar Project (the "Power Plant").

<u>Application Details</u>

In Approval 23951-D02-2019, the AUC approved the Power Plant four kilometres north of the Town of Drumheller, in Starland County, directly adjacent to the Drumheller Municipal Airport ("the Airport").

In this application, Aura applied for approval to amend the power plant to utilize a combination of fixed-tilt and single-axis tracking solar panels, change the model and total number of inverter transformers used in the power plant, and remove the battery storage units. Aura later filed an update to its amendment application to change the configuration of the proposed solar panels from two panels in portrait layout, to one panel in portrait layout. Aura also proposed the exclusive use of single-axis tracking solar panels, rather than a combination of single-axis tracking panels and fixed-tilt panels.

The Power Plant would consist of 207,714 single-axis tracking solar photovoltaic panels and 18 inverter transformer pairs and would have a total generating capability of 75 MW. A solar glare report was completed by Green Cat Renewables Canada Corporation ("Green Cat") for the project for Aura. Green Cat concluded that there would be a glare impact to pilots using the southbound flight path approaching the Airport. Aura committed to implement the mitigation plan developed by Green Cat to eliminate the yellow-grade glare along the southbound flight path.

Intervener Submissions

Solas Energy Consulting Inc. ("Solas") submitted a solar glare report on behalf of the Solar Opposition Participants Group ("SOP"). The SOP argued that Aura's proposed mitigation plan would not address all the predicted solar glare impacts. Given the potential public safety risk to pilots, the SOP requested that the AUC deny the application. Should the application be approved, the SOP requested that a number of conditions were imposed, including that Aura comply with a mitigation plan developed by Solas.

The Town of Drumheller (the "Town") argued that the project was in violation of the *Canadian Aviation Regulations.* The Town also submitted that the perception of increased risk to pilots resulting from the project would have economic impacts for local industries that relied on the Airport.

Scope of the Decision and Inclusion of Flight Routes

In its report, Solas evaluated 29 flight routes, which represented various landing, takeoff and circling approached to the Airport, including one flight path that had not been considered in the original proceeding ("FP5"). The SOP noted that the Airport was an uncontrolled aerodrome, and pilots were required to rely on a "see or be seen" principle for takeoff, landing and performing circling approach flight circuits. The SOP argued that consideration of the flight paths and flight routes would be critical to evaluating the risks associated with solar glare for local pilots.

Aura submitted that inclusion of FP5 and other flight routes was beyond the scope of the amendment application and that there was no need for the AUC to consider any route beyond those assessed in the original proceeding.

Standard Flight Paths and Circling Approaches

The AUC noted that, while not determinative, expert evidence in the original proceeding which had relied on United States Federal Aviation Administration ("FAA") guidelines was instructive in determining what constitutes a standard flight path. The AUC had identified FP1 through FP4 are standard takeoff or landing flight paths and found that FP1 and FP2 were in regular and common use. However, evidence in this proceeding did not support that FP5 or any of the other new flight routes corresponded with the FAA definition of "final approach path". It was also not established that they were in common or regular use.

The AUC noted that the SOP provided little information explaining the usership or the frequency of use of these flight routes in this proceeding and, more significantly, no such evidence was provided in the original proceeding.

Despite unsatisfactory responses from the SOP to an AUC request for more information on why the new flight routes had not been raised in the original proceeding, the AUC recognized the public interest benefit in considering factors recommended by Transport Canada. In these circumstances, this included circling approaches. The AUC concluded that Circ1Large was the only newly introduced flight route with a reasonable basis of inclusion in this proceeding.

Incremental Yellow-Grade Glare

The AUC considered whether FP1 through FP4 and Circ1Large were expected to experience incremental yellow-grade glare as a result of the amendments. Evidence provided by Solas indicated that only FP2 and Circ1Large would experience an increase in yellow-grade glare as a result of the project, as compared to the original approval.

The AUC determined that only FP2 and Circ1Large fell within the scope of the proceeding.

FP2 and Circ1Large

Glare Impacts to Pilots Using FP2

The AUC was not persuaded that a +/- 15 degree range suggested by Green Cat as being sufficient to address glare that could affect pilot safety. The AUC determined that the evidence suggested that a +/- 50 degree range, as supported by Solas, was conservative; however, in the absence of a detailed mitigation plan for angles between +/-15 degrees and +/-50 degrees, the AUC found it reasonable and in the public interest to accept the mitigation plan that corresponds to the +/- 50 degree viewing angle range. This was based on the FAA study's conclusion that yellow-grade glare adversely affects pilots within a +/- 25 degree viewing angle range and the AUC's interpretation of the FAA recommendations that yellow-grade glare would have the potential to adversely affect pilots between 25 and 50 degrees. Accordingly, to ensure that there is no yellow-grade glare along FP2, the AUC required that Aura implement software controls on the solar panels within subarrays 17, 18 and 19, as stipulated in the mitigation plan for the removal of yellow-grade glare on the southbound flight path prepared by Solas based on a horizontal viewing angle range of +/- 50 degrees.

Glare Impacts to Pilots Using Circ1Large

Green Cat predicted there would be no glare on Circ1Large. Solas predicted up to 35,507 minutes of yellow-grade glare along the flight circuit.

While the AUC noted that it found a +/- 15 degree horizontal viewing angle insufficient to address glare that could affect pilot safety, it found it unnecessary to make findings in this proceeding on the preferred methodology when modelling flight circuits or confirming the amount of yellow-grade glare expected on Circ1Large.

The AUC was satisfied that while specific software mitigation was required to eliminate yellow-grade glare along FP2, the glare impact to pilots on Circ1Large could reasonably and effectively be mitigated by the use of adequate sunglasses and that the implementation of software controls was not required. While the AUC acknowledged that pilots were not required to wear sunglasses or carry them on their flights, it noted that this was consistently recommended by aviation authorities and sunglasses were a common aviation item.

Other Findings

The AUC determined that a participant involvement program had been conducted before a facility application was filed with the AUC. Therefore, the technical aspects of the Power Plant amendment met the requirements of Rule 007.

The AUC found that Aura's project-specific mailout in respect of the amendment application allowed potentially affected stakeholders, including the SOP members, to understand the nature of the application well enough to identify any specific areas of concern. Regarding the SOP's concern that the project mailout did not specifically identify the change in solar glare modelling parameters, the AUC noted that this degree of detail was not generally required at this level of notification.

As Rule 033*: Post-approval Monitoring Requirements for Wind and Solar Power Plants* had come into effect and applied to the project, the AUC noted that Aura was required to comply with the requirements of Rule 033. Accordingly, the AUC imposed, as a further condition to the approval, that Aura submit an annual post-construction monitoring survey report to Alberta Environment and Parks ("AEP") and the AUC within 13 months of the project becoming operational, and on or before the same date every subsequent year for which AEP requires surveys pursuant to section 3(3) of Rule 033.

***Elemental Energy Renewables Inc. Chappice Lake Solar Project Alteration,* AUC Decision 26213-D01-2021**
Facilities - Solar Plant

In this decision, the AUC approved an application from Elemental Energy Renewables Inc. ("Elemental Energy") to alter the Chappice Lake Solar Project (the "Project") by adding a 3.6-megawatt/10-megawatt hour battery for energy storage. Elemental Energy also finalized its selection of solar panels, racking system and inverter/transformer station. The 15-megawatt solar power plant, designated as the Chappice Lake Solar Project (the "Project"), located in the area of Bowmanton, Alberta, had been approved by the AUC in Decision 25451-D01-2021.

Application Details

In support of the addition of the 3.6-megawatt/10-megawatt hour vanadium flow battery to the Project, Elemental Energy stated that the battery would help provide renewable electricity, avoid renewable power curtailment, and time-shift electricity production to discharge at times of peak demand. The export capability would remain unchanged at the approved rating of 15-megawatts.

Elemental Energy confirmed that it had selected 47,320 Longi Solar's LR4-72HBD-440 and LR4-72HBD-445 solar panels and finalized its inverter and transformer selections. The racking design was revised to a single-axis-tracking system.

AUC Findings

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

The AUC found that application requirements specified in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments,* and the noise impact assessment requirements of Rule 012: *Noise Control* had been met.

Alberta Environment and Parks ("AEP") submitted that it had no new concerns related to wildlife and wildlife habitat disturbance as a result of the applied for changes. As the battery would be contained in a steel shipping container, and because the addition of the battery and final Project layout components would not expand the final Project boundary beyond what had been approved, the AUC found that the Project would have minimal environmental effects.

In accordance with Rule 033: *Post-Approval Monitoring Requirements of Wind and Solar Power Plants,* as a condition to the approval, the AUC required that Elemental Energy submit an annual post-construction monitoring survey report to AEP and the AUC within 13 months of the Project becoming operational, and on or before the same date every subsequent year for which AEP requires a survey pursuant to Subsection 3(3) of Rule 033.

No public safety standards or regulations governing solar glare existed at the time of this application. The AUC accepted the conclusion of the glare impact review provided by GreenCat Renewables Canada that the Project would not be predicted to produce a glare impact at any receptor. The AUC imposed the following as conditions of approval:

(a) Elemental Energy Renewables Inc. shall use a standard anti-reflective coating for the Project's solar panels.

(b) Elemental Energy Renewables Inc. shall file a report detailing any complaints or concerns it receives or is made aware of regarding solar glare from the Project during its first year of operation, as well as Elemental Energy Renewables Inc.'s response to the complaint. Elemental Energy Renewables Inc. shall file this report no later than 13 months after the Project becomes operational.

As Elemental Energy had satisfied the condition that the final selection of equipment for the Project would not increase the land, noise, or environmental impacts beyond those reflected in its previous application, this condition was removed from Approval 25452-D02-2020.

Enbridge Pipelines Inc. Application for an Order Permitting the Sharing of Records Not Available to the Public Between Enbridge Pipelines Inc. and URICA Energy Real Time Ltd., **AUC Decision 26257-D01-2021**
Fair, Efficient and Open Competition Regulation - **Sharing of Records**

In this decision, the AUC granted the application from Enbridge Pipelines Inc. ("Enbridge") for an order to permit the sharing of records pertaining to the electricity and ancillary services markets under Section 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation"*).

<u>Introduction and Procedural Background</u>

Enbridge filed an application seeking permission to share records not available to the public between Enbridge and URICA Energy Real Time Ltd. ("URICA"), relating to the 20.01-megawatt (MW) South Edmonton Terminal Power Generation Facility (asset ID SET1).

<u>AUC Findings</u>

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

The AUC was satisfied that Enbridge had demonstrated that (i) the sharing of records with URICA was reasonably necessary for Enbridge to carry out its business; and (ii) the subject records would not be used for any purpose that did not support the fair, efficient and openly competitive operation of the Alberta electricity market, including the conduct referred to in Section 2 of the *FEOC Regulation*. Relying on submissions from Enbridge and written representations from Enbridge and URICA, the AUC was satisfied that Enbridge and URICA would conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market.

The AUC further found that Enbridge's and URICA's total offer control were well below the maximum of 30 per cent, set out in Subsection 5(5) of the *FEOC Regulation.*

Given the Market Surveillance Administrator's ("MSA")'s mandate under Subsection 39(2)(a)(vi) of the *Alberta Utilities Commission Act,* the AUC considered the MSA's support of this application to have been a contributing factor in the decision to permit the sharing of records.

The AUC approved the application.

EPCOR Distribution and Transmission Inc. 2021 Customer Specific Distribution Access Service Rate Update for an Existing Customer (CS24)**, AUC Decision 26231-D01-2021**
Rates

In this decision, the AUC approved EPCOR Distribution & Transmission Inc.'s ("EPCOR") updated 2021 customer specific ("CS") distribution access service ("DAS") rate for an existing customer CS24.).

<u>Background</u>

The CS rate class consists of customers with annual energy demands over 5000 kilowatts ("kW"). EPCOR identified modifications required to accommodate the changes requested by customer CS24. EPCOR used the same methodology to calculate the rate in this application as had been used and approved for a previous CS customer, in Decision 26120-D01-2020.

Calculation of the 2021 CS24 Rate

EPCOR's cost-of-service calculation included three components: incremental equipment and installation activities; cost of existing assets to provide service; and allocated operating, maintenance and general ("OM&G") costs. While standby service was not required for the customer site, it was requested by the customer. EPCOR requested that the customer provide a capital contribution for any new assets required to provide standby service. Capital assets dedicated for the customer as well as assets shared with other sites would be installed to provide standby service for CS24. The cost of dedicated assets would be charged exclusively to the customer requiring them. The cost of shared assets would be allocated proportionally based on minimum contracted demand.

EPCOR categorizes assets installed during the first year of a CS rate as incremental assets. Thus, for CS24, the assets installed in 2021 were incremental assets for the purposes for calculating the customer's 2021 CS rate. In this application, the capital costs of dedicated incremental assets were entirely assigned to the customer.

To calculate the revenue requirement associated with the capital-related costs included in the CS rate, EPCOR used a 2021 estimated weighted average cost of capital ("WACC") rate of 6.06 per cent.

EPCOR allocated OM&G costs associated with the incremental and existing assets using a ratio of 1.851 per dollar of capital costs. EPCOR calculated the ratio between total OM&G costs and capital costs based on the amounts filed in its 2010-2011 Phase II compliance filing.

AUC Findings

The AUC noted that the cost-of-service methodology used by EPCOR to calculate the CS24 rate adjustment was the same as the methodology most recently confirmed in Decision 26120-D01-2020. The AUC found the proposed CS24 rate update reasonable and approved the CS24 rate of $576.39 per day, effective May 1, 2021.

EPCOR was directed to true up any differences if the actual effective date for the revised CS24 rate differs from the effective date contemplated in this decision. The CS24 rate would also be trued up to reflect the 2021 actual cost of debt when this became available.

EPCOR was reminded of the direction to examine the relevance of using capital costs to allocate OM&G costs in its next Phase II application. EPCOR was directed to consider whether the use of a static OM&G allocation ratio that is unchanged during the performance-based regulation term resulted in the efficient and fair allocation of OM&G costs across all of EPCOR's customers. Alternatively, if there was a need for another mechanism to efficiently and fairly address material differences between the incremental OM&G costs incurred by EPCOR as new customers are added to the CS rate class.

The AUC emphasized that, in approving this application, it did not permit the recovery by EPCOR of any amount payable by the customer from other customers in the event of default or bankruptcy of CS24.

***EPCOR Distribution & Transmission Inc. 2021 System Access Service Rate Update,* AUC Decision 26256-D01-2021**

Rates

In this decision, the AUC approved the application from EPCOR Distribution & Transmission Inc. ("EPCOR") for an update to its 2021 system access service ("SAS") rates, effective April 1, 2021.

Background and Details of Application

EPCOR SAS rates are designed to recover charges paid by EPCOR to the Alberta Electric System Operator ("AESO") for access to the transmission system.

In Decision 25866-D01-2020, the AUC had approved EPCOR's 2021 SAS rates together with EPCOR's 2021 performance-based regulation rates. Shortly after, the AUC issued Decision 26054-D01-2020 regarding the

AESO's 2021 Independent System Operator ("ISO") tariff update and approved changes to all of the AESO demand transmission service ("DTS") rate components. In this application, to update its SAS cost-of service model to align with the changes to the AESO DTS rate components, EPCOR requested approval to update its 2021 SAS rates, effective April 1, 2021.

EPCOR submitted an updated calculation of its 2021 SAS rates. The only change in the inputs for 2021 from those approved in Decision 25866-D01-2020 were the AESO DTS rates. EPCOR further submitted a bill comparison to indicate the impact of the updated SAS rates from March 2021 to April 2021 for a typical customer in each of its rate classes. The bill impact to each rate class was less than 10 per cent.

AUC Findings

The AUC found that the calculation of the proposed 2021 SAS rates was consistent with past SAS rate applications. The AUC also found the bill impacts to be reasonable. The AUC approved EPCOR's proposed update to its 2021 SAS rates, as filed, to reflect the changes to the DTS rates approved in the AESO's 2021 ISO tariff update.

FortisAlberta Application for Orders Confirming Boundaries of FortisAlberta Inc. Exclusive Municipal Franchise Areas, **AUC Decision 25644-D01-2021**
Municipal Franchise Areas - Rural Electrification Associations

In this decision, the AUC considered an application under Section 29 of the *Hydro and Electric Energy Act* ("*HEEA*") from FortisAlberta Inc. ("FortisAB") concerning the boundaries of ForitsAB's municipal franchise areas ("MFA")s. The AUC:

- Confirmed FortisAB's service area boundaries ("FortisAB's expanded service areas");
- Altered the service area boundaries of rural electrification associations ("REAs") to prevent incursion into FortisAB's exclusive service areas under the MFAs, as required;
- Ordered, consistent with the bylaws issued by the Town of Penhold ("Penhold") and the Town of Bruderheim ("Bruderheim"), the transfer, as soon as practicable, of REA facilities and customers located within FortisAB's expanded service areas under the MFA's granted to FortisAB by those municipalities;
- Ordered the eventual transfer of existing REA customers and associated facilities within the remainder of FortisAB's expanded service areas to FortisAB consistent with the AUC's findings in Decision 22164-D01-2018.
- Denied FortisAB's request for the transfer of REA assets that are located within FortisAB's expanded service areas but are not used to serve a REA member within those service areas namely, those located within the Town of Millet, the Town of Fort Macleod and the Summer Village of West Cove.

Discussion of Issues and AUC Findings

Annexed Distribution Service Area and REA Members Are Being Served by the REA Within the Annexed Boundary

In Proceeding 22164, the AUC examined the legislative and public interest considerations to determine whether to alter electric distribution service area boundaries to align with the MFAs entered into between FortisAB and various municipalities whose corporate boundaries had expanded through annexation and overlapped with an existing REA service area. In all those instances examined in that proceeding, there were REA members being served by the REA within the annexed distribution service area. In this proceeding's decision, the AUC confirmed FortisAB's exclusive franchise areas to correspond to the corporate limits of the municipalities. However, the AUC did not require the immediate transfer of existing REA facilities and members in the annexed distribution service areas absent a municipal bylaw requiring those members to connect to FortisAB.

In the current application, FortisAB estimated that approximately 21 members were being served by REAs in annexed distribution service areas, and that REA-owned distribution facility assets were in about 24 locations within municipal corporate limits.

FortisAB stated that in accordance with Decision 22164-D01-2018, it did not expect the immediate transfer of the REA members or facilities in the annexed distribution service areas. Rather, it asked for orders confirming FortisAB's exclusive service areas in 14 municipalities, and that:

> Any existing REA member, who is currently taking electric distribution service from one of the affected REAs within the corporate limits of a municipality identified in Appendix A to this Application, may continue to be served by the REA until such time as the municipality passes a bylaw requiring the REA members in the municipality to take electric distribution service from FortisAlberta. If a municipality does not pass any such further bylaw, the affected REA has the Commission's approval to continue to serve an existing REA member within the municipality's boundaries until the earliest of: (i) the existing REA member electing to transfer to FortisAlberta, (ii) a change in the member of service (such as a change in ownership of the applicable site), (iii) the affected REA requesting the transfer of the member and associated facilities to FortisAlberta, and (iv) the affected REA refusing to continue to serve the existing member.

The AUC confirmed FortisAB's exclusive service areas to correspond with the municipal corporate limits and ordered the transfer of REA assets and members in the annexed distribution service areas in accordance with the conditions outlined in Decision 22164-D01-2018.

The AUC found hat the Town of Millet, the Town of Penhold and the Town of Bruderheim had each passed bylaws pursuant to Section 46 of the *Municipal Government Act* ("*MGA*") requiring the REA members in those respective municipalities to take electric distribution service from FortisAB. Consistent with the bylaws passed by those municipalities, the transfer of REA assets and REA members within the corporate limits of the Town of Penhold and the Town of Bruderheim to FortisAlberta was ordered to be completed as soon as practicable.

Annexed Distribution Service Area and No REA Members Are Being Served by the REA Within the Annexed Boundary

Evidence provided in this proceeding showed three instances of REA distribution system assets located within municipal corporate limits that do not serve REA member sites within those boundaries: two belonging to EQUS in the Town of Fort Macleod and the Summer Village of West Cove, and one belonging to Battle River in the Town of Millet.

FortisAB argued that the ownership transfer of these pass-through assets would be in the public interest as the elimination of overlapping service areas would reduce or eliminate the need for an integrated operation agreement to govern the operation of an intermingled system. It added that EQUS and Battle River would be fairly compensated for their assets and that REA members located outside the service area boundaries would not experience an interruption in service from their REAs.

The AUC had previously found in Decision 22164-D01-2018, that the MFAs and the municipalities' exercise of authority pursuant to the *MGA*, including section 45, was subsumed under the broader issue of what is in the public interest.

For the purposes of this analysis, the AUC considered sections 45 to 47 of the *MGA,* sections 29 and 32 of the *HEEA* and section 8 of the *Alberta Utilities Commission Act* ("*AUC Act*").

The AUC noted that a plain reading of sections 29 and 32 of the *HEEA* grants authority to the AUC, when it is in the public interest to do so: (i) to reduce the service area of an REA and, as part of its public interest consideration; and (ii) order the transfer of any facilities of the electric distribution system of the REA to another party for the purpose of ensuring the continued distribution of electric energy in the service area or part that was served by the REA.

An alteration of the REA service area took place. The municipal boundary had expanded through annexation. The AUC held it was in the public interest to order that the reduction of the size of the REA service area conform with the boundaries governed by the MFAs.

FortisAB further requested an order requiring the transfer of REA assets upon the passage of a bylaw by the municipality pursuant to Section 46 of the *MGA*, an existing REA member wanting to be served by FortisAB or the REA no longer wanting to serve the member.

Evidence provided in this proceeding did not convince the AUC that the transfer of these assets was necessary to ensure continued distribution of electric energy within the annexed area. The AUC could therefore not rely on its authority under section 32(2)(b) to order the transfer of these assets to FortisAB.

The AUC noted that it has the general authority pursuant to Section 8 of the *AUC Act* to do all things that are necessary for or incidental to the exercise of its powers and the performance of its duties and functions. The AUC considered whether this general authority could authorize the transfer of the pass-through assets. It noted that provisions in the *HEEA* authorize the AUC to give effect to a change in a service area; issue such orders concerning the transfer of facilities as are considered necessary to ensure that customers continue to receive service in the service area; and provide for fair compensation to the REA. Comparatively, Section 8 of the AUC Act is a more general provision. Consistent with the rules of statutory interpretation, the AUC found that it cannot apply its section 8 authority in substitution for the explicit provisions in the *HEEA* that detail the Commission's authority in the circumstances of a change in service area.

Accordingly, in those municipalities where there are pass-through assets, the Commission orders\ed the size of the REA service area be reduced to conform with the MFA pursuant to section 32(1)(a) of the *HEEA*. However, the transfer of the pass-through assets to FortisAlberta was not directed.

<u>Order</u>

The AUC confirmed FortisAB service areas outlined in a list in the decision. The AUC denied FortisAB's request for the transfer of REA-owned assets located within FortisAB's expanded service areas, but not used to serve an REA customer within those service areas namely, those located within the Town of Millet, the Town of Fort Macleod and the Summer Village of West Cove.

Pembina Gas Services Ltd. Kakwa River Gas Plant Industrial System Designation, **AUC Decision 26117-D01-2021**

Industrial System Designation

In this Decision, the AUC approved the application from Pembina Gas Services Ltd. ("Pembina") for an industrial system designation ("ISD") that encompassed electric facilities at the Kakwa River Gas Plant industrial site including the Musreau Power Plant.

<u>Introduction</u>

Pembina owns and operates the sour gas processing facility and the associated 20.59-megawatt (MW) Musreau Power Plant at its Kakwa River Gas Plant industrial complex. Pembina requested that the AUC designate the electric facilities as an industrial system to allow for connecting the existing power plant to the Alberta Interconnected Electric System ("AIES"). In its application, Pembina requested:

- An industrial system designation encompassing all the electric facilities at the Pembina industrial site pursuant to section 4 of the *Hydro and Electric Energy Act* ("*HEEA*").
- An exemption from the operation of the *Electric Utilities Act* ("*EUA*") for the electric energy produced from and consumed by the industrial system.

Discussion

The Kakwa River Gas Plant contains a power plant, designated as the Musreau Power Plant, that consists of three 5.63-MW natural gas-fired generating units, one 1.4-MW natural gas-fired unit and two emergency diesel generating units with a total capability of 20.59 MW. Pembina clarified that the 1.4-MW natural gas-fired generating unit was decommissioned.

Pembina explained that the Kakwa River Gas Plant was constructed prior to the completion of ATCO Electric Ltd.'s Thornton 2091S Substation. Due to distribution capacity restrictions and lack of nearby distribution infrastructure, the previous gas plant owner opted to self-supply electricity through the construction of the Musreau Power Plant. Pursuant to Decision 21583-D02-2016 Pembina has an exemption to own and operate the power plant for its own use.

Pembina explained that the natural gas-fired generating units have historically been operated at approximately 40 per cent of their nameplate power rating. At less than half of their capacity, the natural gas-fired generating units cannot provide the thermal energy required by the Kakwa River Gas Plant and the industrial processes must be supplemented by gas-fired heaters. Pembina stated that connecting to the AIES would allow the three natural gas-fired generating units to operate at full load thereby enabling the facility to fully utilize waste heat, limiting the requirement for gas-fired heaters.

Pembina submitted that there would be a significant and sustained increase in efficiency to the power plant by fully utilizing the natural gas-fired generating units and associated waste heat recovery units. Pembina stated that the generating units would improve their energy efficiency by approximately 38 per cent as a result of connecting to the AIES and being used at full capacity.

Pembina submitted that it was applying for an ISD to allow for excess electricity to be exported to the AIES during times when the generation capacity exceeded the power demand.

AUC Findings

The AUC found, that granting the requested ISD was consistent with the principles set out in Subsection 4(2) of the *HEEA* and with the criteria set out in Subsection 4(3) of the *HEEA.*

The AUC noted that it understood that Pembina sought an ISD to allow for the connection to the AIES with the intent to export electricity produced by the power plant in excess of the facilities' electricity load. Importantly, the natural gas-fired turbine generators produce both electricity and heat that is used for the industrial operations of the facility. Pembina has stated that 100 per cent of the heat produced at full capacity will be used for heating requirements of the plant and that connecting to the AIES would improve the efficiency of the power plant.

The AUC was satisfied that Pembina's proposal to export excess electricity would facilitate the efficient exchange with the AIES of electric energy exceeding Pembina's own electricity requirements, but which must be generated to meet the heating requirements of the facility.

The AUC was satisfied that Pembina was not seeking an ISD to avoid system costs. The AUC considered that the power plant was reasonably scaled to meet the electricity and heating needs of the Kakwa River Gas Plant. The AUC observed that it would be impractical to precisely scale on-site generation for a specific thermal or electrical output given the need for operational variability and having regard for reasonable expansion or growth of the industrial operations. The AUC accepted that the power plant was constructed to serve the industrial operations at a time when the facility could not connect to the AIES and it was not expected that the facility would connect to the AIES. Therefore, the AUC accepted that the decision to install generation capacity in excess of the site's electricity needs was reasonable and was taken to ensure the provision of reliability, stability and heat to the Kakwa River Gas Plant.

Having considered the applicable principles and criteria set out in Section 4 of the *HEEA,* the AUC determined that Pembina's proposal met the principles and criteria for an ISD. The application was approved.

CANADA ENERGY REGULATOR

***The Explorers and Producers Association of Canada Application to Extend the NOVA Gas Transmission Ltd. Gas Transportation Temporary Service Protocol Tariff Provision*, CER Letter Decision**
Rates - Temporary Service Protocol

In this decision, the CER denied the Application from the Explorers and Producers Association of Alberta ("EPAC") 28 July 2020 application to extend the NOVA Gas Transmission Ltd. ("NGTL") Gas Transportation Temporary Service Protocol ("TSP") Tariff Provision which expired 31 October 2020, until the earlier of 31 October 2021 or until leave to open of the final component of the NGTL 2021 System Expansion Project.

The CER issued Order TG-001-2021 which requires NGTL to address access to storage with a future filing with the CER. Further reasons will follow.

***Trans Mountain Expansion Project Certificate of Public Convenience and Necessity OC-065 Austeville Properties Ltd. Detailed Route Hearing MH-023-2020*, CER Letter Decision**
Pipelines - Route Hearings

<u>Background</u>

On December 16, 2013, Trans Mountain Pipeline ULC ("Trans Mountain") filed an application with the National Energy Board ("NEB") under section 52 of the *National Energy Board Act* ("*NEB Act*") for a certificate of public convenience and necessity ("Certificate") authorizing the construction and operation of the Trans Mountain Expansion Project ("TMEP").

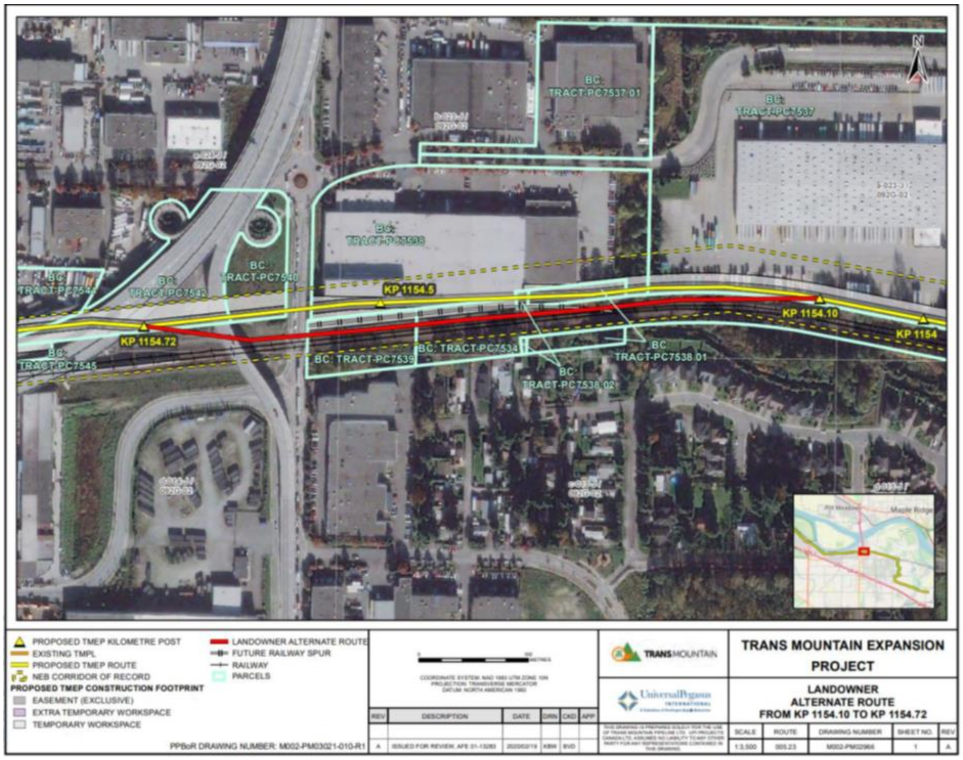
The TMEP includes twinning the existing 1,147-kilometre-long Trans Mountain Pipeline ("TMPL") system in Alberta and British Columbia with approximately 981 kilometres of new buried pipeline; new and modified facilities, such as pump stations and additional tanker loading facilities at the Westridge Marine Terminal in Burnaby; and reactivating 193 kilometres of the existing pipeline between Edmonton and Burnaby. Trans Mountain requested approval of a 150-metre-wide corridor for the TMEP pipeline's general route.

Following an approval by Order in Council ("OIC"), an appeal, a second public hearing process, an NEB Reconsideration Report, and a further approval of the TMEP by an OIC, the NEB issued Certificate OC-065. In July 2019, following a public comment process, the NEB set out how it would resume the TMEP detailed route approval process. The NEB directed Trans Mountain to file its Plan Profile and Book of Reference ("PPBoR") for the entire TMEP route. Trans Mountain served landowners along the length of the TMEP with a notice that the detailed route approval process was underway, and placed notices in local publications. The notices indicated that landowners and Indigenous peoples with a continued or new objection to the proposed detailed route, or to the methods or timing of construction, were required to file a statement of opposition ("SOO"). On August 28, 2019, the *Canadian Energy Regulator Act* ("*CER Act*") came into force, repealing the *NEB Act*. As a result, the CER is considering approval of the PPBoR under the provisions of the *CER Act*.

<u>Detailed Route Hearing MH-023-2020</u>

Austeville Properties Ltd. ("Austeville") is the registered owner of lands identified as Tract 7538 in Segment 6.8 on PPBoR Sheet M002-PM03021-010 filed by Trans Mountain (C00974-9). Tract 7538 was referred to in this decision as the "Lands". Figure 1 below shows Trans Mountain's proposed route, and Austeville's proposed alternate route, across the Lands.

Figure 1 – Trans Mountain's proposed route (in yellow), and Austeville's proposed alternate route (in red), across the Lands (C04884-1, PDF page 5)



<u>Is Trans Mountain's Proposed Detailed Route the Best Possible Detailed Route?</u>

Austeville argued that its alternate route aligned better with Trans Mountain's routing criteria.

The CER held that the Trans Mountain's routing criteria and other guidelines prioritize safety and consider competing factors, including physical constraints, while attempting to minimize environmental and socio-economic impacts on land and landowners. Trans Mountain's routing criteria are also flexible enough to incorporate reasonable mitigation measures to respond to concerns raised by landowners. Accordingly, the CER assessed whether Trans Mountain's proposed route reflected an appropriate application of its routing criteria, while considering its proposed mitigation measures to address Redwoods' concerns. The CER found that that Trans Mountain applied its routing criteria appropriately.

The CER agreed that the proposed route was consistent with its routing criteria, since the TMPL right of way ("RoW") is not near the Lands and the proposed route follows the existing CN Rail RoW. However, as Austeville identified outstanding concerns with the route and suggested an alternate route, the CER considered Austeville's alternate route to determine if Trans Moutains' proposed route was the best possible route.

Considering the Concerns and the Alternate Route Raised by Austeville, is Trans Mountain's Proposed Route the Best Possible Detailed Route?

Having considered the evidence of the parties, the CER was not persuaded that Trans Mountain had met the burden to establish that its proposed route was the best possible detailed route. Austeville's concerns about the proposed route were not enough to convince the CER that the route should be denied. However, the CER noted that Austeville had gone to extraordinary lengths to demonstrate the feasibility of its preferred alternate route. Having considered the alternate route, Trans Mountain failed to persuade the CER that the proposed route was the best possible detailed route.

Is Trans Mountain's Proposed Timing of Construction the Most Appropriate?

Construction timing is scheduled between Q1 and Q2 of 2021. The CER acknowledged that Trans Mountain may have determined its proposed construction timing based on its proposed route through Austeville's Lands. As a result of the CER's decision regarding the proposed route, the CER did not make a determination regarding the most appropriate timing of construction in this decision.

Trans Mountain Expansion Project Reasons for Decision MO-002-2021, **CER Letter Decision**

Interjurisdictional Immunity - Federal Paramountcy

This Order provided the CER's reasons for granting Motion C10426 (the "Motion"), filed by Trans Mountain on December 15, 2020. The CER granted to Trans Mountain: (i) relief from obtaining tree cutting permits under the City of Burnaby's ("Burnaby") bylaw ("Tree Bylaw") for all Project-related tree clearing within Burnaby; and (ii) section 3 of the Tree Bylaw is inapplicable and inoperative under the doctrine of interjurisdictional immunity and federal paramountcy and therefore inoperative to the tree clearing.

The MH-002-2021 Proceeding

In the Motion filed by Trans Mountain with the CER, Trans Mountain made requests, including that the CER:

(a) Grant relief pursuant to Certificate Condition 1 from Certificate Condition 2, insofar as it requires Trans Mountain to obtain Tree Cutting Permits under section 3 of the Burnaby's Bylaw No. 10482 ((referred to as the Tree Bylaw) for all Project-related tree clearing within Burnaby (defined in the Motion as Tree Clearing);

(b) Issue an Order pursuant to sections 32, 34 and paragraph 313(i) of the *Canadian Energy Regulator Act* ("*CER Act*") declaring that:

- The constitutional question raised in the Motion is answered in the affirmative;
- Section 3 of the Tree Bylaw is inoperative, invalid and/or does not apply with respect to the Tree Clearing; and
- Trans Mountain may proceed with the Tree Clearing all Project-related tree clearing within Burnaby pursuant to the terms and conditions of the certificate and related orders notwithstanding the fact that Burnaby has not issued Tree Cutting Permits under section 3 of the Tree Bylaw for the Tree Clearing; and

(c) Adjudication of the Motion expeditiously and in accordance with the generic process set down by the Process Order.

The City of Burnaby Tree Law

Section 3 of the Burnaby Tree Bylaw requires Trans Mountain to obtain Tree Cutting Permits for all Project-related clearing of certain protected trees within Burnaby. Section 5 sets out the requirements for a Tree Cutting Permit Application, including payment of a permit fee and submission of a tree plan.

On December 7, 2020, Trans Mountain applied for a permit to conduct tree clearing on private and municipal lands (the "Application") in Burnaby and sought a decision by 11 December 2020. Trans Mountain indicated in the covering letter to the Application that "[s]hould a decision not be forthcoming by this date, Trans Mountain will take steps to secure necessary approvals to complete this work."

On December 9, 2020, Burnaby denied Trans Mountain's application. Burnaby stated that "[a]t this time, the City is not prepared to consider the application given that Trans Mountain does not accept the City's jurisdiction and intends to make an application to the CER."

<u>Constitutional Question</u>

The Motion raised the following constitutional issue:

> Whether, on the facts before it, the CER should find that the requirement for municipal approval under section 3 of the Tree Bylaw prior to conducting the Tree Clearing is inapplicable, invalid, or inoperative under the doctrines of interjurisdictional immunity and/or federal paramountcy.

The CER noted the parties' agreement on several threshold matters:

(a) There was no dispute that the CER has the authority to decide the constitutional question;

(b) There is no dispute that the Tree Bylaw is a properly enacted and a valid exercise of provincial authority; and

(c) There is no dispute about the constitutional law governing interjurisdictional immunity and paramountcy. The dispute between the parties pertains to whether these constitutional doctrines apply on the facts.

The CER found, based on the facts before it, that section 3 of the Tree Bylaw is inapplicable and inoperative under the doctrine of interjurisdictional immunity and federal paramountcy. The CER reached its conclusion on the basis that Burnaby's refusal to process the application represents a frustration of a federal purpose and serious impairment of a core competence of Parliament and a federal undertaking.

Paramountcy

The CER found that the facts of this case established that the City of Burnaby's refusal to process the Application since December 7, 2020, without legislative authority on which it relied to do so, had the effect of frustrating a federal purpose in this specific instance.

- The Project had been held to be in the Canadian public interest and Trans Mountain has broad powers to carry out its construction under section 313 of the *CER Act*. Moreover, Burnaby already reached an agreement with Trans Mountain on the detailed route and methods of construction for the Project;

- The Tree Clearing was necessary to proceed with the Project and Trans Mountain should have been able to begin Tree Clearing in January 2021 to maintain the Project construction schedule and avoid environmentally sensitive windows;

- Burnaby had never issued a Tree Cutting Permit for Trans Mountain's Project even in the circumstances of danger trees needing removal;

- In its 9 December 2020 letter, Burnaby refused to process the Application. While Burnaby qualified the refusal being "at this time", Burnaby could not provide an estimate of the time it needed to process the Application;

- Burnaby confirmed that since its December 9, 2020 refusal letter, it had not taken any steps to process the Application. This, despite an amended Tree Management Plan being filed on December 18, 2020 indicating that Trans Mountain continued to pursue the permitting process and despite weeks lapsing between December 7, 2020 and argument being heard on the Motion on January 29, 2021;

- Burnaby confirmed that it was reasonable to assume that the Tree Cutting Permit Application is unlikely to be approved as filed; and

- Burnaby's refusal to process the Tree Cutting Permit Application since it has been validly filed on 7 December 2020 through to the time of the closing of the record for the hearing on 29 January 2021, caused, or was a significant contributing or exacerbating factor to, delay the Tree Clearing. Trans Mountain has obtained all regulatory approvals including plan, profile and book of reference approval, and had satisfied the pre-construction conditions required to conduct the Tree Clearing, except for the Tree Cutting Permit at issue.

Therefore, the CER found that Burnaby's refusal to process the Application was frustrating Trans Mountain's exercise of its authorizations under the certificate and other NEB / CER orders, and its powers under section 313 of the *CER Act*. Accordingly, the doctrine of paramountcy applies to render section 3 of the Tree Bylaw inoperable to the extent that it frustrates Trans Mountain's ability to proceed with the Project which was found to be in the Canadian public interest.

Interjurisdictional Immunity

The CER maintained that matters of *when* and *where* the Project can be carried out, and its orderly development, fall within the "core" of federal jurisdiction over interprovincial undertakings and are vital to the Project. Accordingly the CER was satisfied that Burnaby's refusal to process the Application trenches into core competences of Parliament and vital part of a federal undertaking. The CER found that Burnaby's refusal to process the Application, intentional or not, (the CER made no finding of intent), was the cause of, or a contributing or exacerbating factor to, delay in Tree Clearing, which had a significant and direct implication on Project timing and construction. In the CER's view, Burnaby's refusal was sufficiently serious in the circumstances to invoke the doctrine of interjurisdictional immunity, rendering section 3 of the Tree Bylaw inapplicable to the extent that it impairs Trans Mountain's ability to perform the Tree Clearing.

The CER found that the constitutional question doctrines apply due to the delay caused by Burnaby's inaction and its refusal to process the Tree Cutting Permit Application, regardless of the nature of Trans Mountain and Burnaby's motives or intentions.

Relief from Certificate Condition 2

The CER determined that it would be in the public interest to relieve Trans Mountain of the requirement under Certificate Condition 2 to obtain a Tree Cutting Permit under section 3 of the Tree Bylaw with respect to the Tree Clearing. The CER reached this conclusion on the basis that there was delay caused by Burnaby's refusal to process the Application. Trans Mountain's Application had been held in abeyance by Burnaby since December 7, 2020 with no indication of imminent resolution and, given the urgency of the Tree Clearing and likely negative effects of delaying Project construction on Trans Mountain, third parties and the environment, the public interest in granting the exemption outweighs the public interest in requiring Trans Mountain to continue with the Tree Cutting Permit process.

Conclusion

The constitutional question raised in paragraph 3 of the Motion was answered in the affirmative. The CER found that the doctrines of federal paramountcy and interjurisdictional immunity render section 3 of the Tree Bylaw inapplicable and inoperative to the Tree Clearing.

The CER also found it to be in the public interest to relieve Trans Mountain of the requirement of Certificate Condition 2, insofar that it requires Trans Mountain to obtain a Tree Cutting Permit for Tree Clearing.

Commitments Made

In addition, the CER expects Trans Mountain to follow through on all the representations and commitments it made on the record of this Motion and described in the reasons for decision on the Motion.

***Trans Mountain Pipeline ULC Application for the Edmonton Terminal Tanks 20, 21 and 22 Deactivation Project Order MO-003-2021*, CER Letter Decision**

Deactivation of Facilities - Onshore Piping Regulations

In this decision, the CER approved the application from Trans Mountain Pipeline ULC ("Trans Mountain") to deactivate the Edmonton Terminal Tanks 20, 21 and 22 (the "Project"), pursuant to section 44 of the Canadian Energy Regulator *Onshore Pipeline Regulations* ("*OPR*").

The CER noted that the deactivated tanks remain subject to the CER's jurisdiction and direction. Trans Mountain was reminded of its continuing obligation to monitor and maintain the tanks. Trans Mountain was further reminded that no pipeline or part of any pipeline than had been deactivated for twelve months or more could be reactivated without leave from the CER.

The CER considered the environmental protection procedures and mitigation that would be implemented by Trans Mountain. In combination with the conditions of approval imposed by the CER, it determined that the Project was unlikely to cause any significant adverse environmental effects. As conditions, the CER required that:

- Trans Mountain maintains the Project in its deactivated state in accordance with the specifications, standards, commitments and other information referred to in its application or in its related submissions.

- Trans Mountain implement or cause to be implemented all of the policies, practices, programs, mitigation measures, recommendations, procedures and its commitments for the protection of the environment included in or referred to in its application or in its related submissions.

- Trans Mountain file, within 30 days of the date of this order, a confirmation with the CER that the Project was completed in compliance with all applicable conditions in this order. If compliance with any of these conditions could not be confirmed, Trans Mountain was required to file with the CER a detailed explanation of why compliance could not be confirmed. This explanation was required to include a statement confirming that the signatory to the filing is the accountable officer of Trans Mountain, pursuant to section 6.2 of the *OPR.*