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 COURT OF APPEAL

EQUS REA Ltd v Alberta (Utilities Commission), 2022 ABCA 61

Tariffs - Cost Allocation

In this decision, the Alberta Court of Appeal ("ABCA") considered the applications from FortisAlberta Inc. ("FortisAB"), EQUS REA Ltd. ("EQUS"), and the Alberta Federation of Rural Electrification Associations ("AFREA") for permission to appeal AUC Decision 25916-D01-2021 regarding FortisAB's 2022 Phase II distribution tariff application.

The ABCA granted permission to appeal to EQUS and FortisAB. The application from the AFREA was denied. Granting the application from the AFREA would have resulted in the duplication of questions. The ABCA noted that the AFREA has the option to participate in the appeals as an intervener.

Background

The central issues identified by the AUC in Decision 25916-D01-2021 (the "Decision") and the issues raised in the applications filed in this proceeding were:

(a) whether FortisAB's proposed distribution cost allocation and resulting percentages provide for a just and reasonable allocation of FortisAB's distribution costs among its customer rate classes and Rural Electrification Associations ("REAs") interconnected with its distribution system;

(b) whether there are costs FortisAB incurs as a result of integrated operations with REAs that should not be borne by FortisAB's customers through its distribution tariff; and

(c) if confirmed, when and how these costs should be removed from the rates charged to FortisAB's distribution customers.

In the Decision, the AUC approved FortisAB's proposed allocation of distribution costs comprising its revenue requirement but held that FortisAB could not recover distribution costs associated with the REAs from their customers. The AUC determined that it does not have the authority to approve distribution costs associated with the REAs. The AUC consequently directed that the REA-related costs must be removed from the rates charged to FortisAB's distribution customers at the time of its 2023 application.

Proposed Grounds of Appeal

FortisAB's proposed grounds of appeal were that:

(a) the AUC erred in law or jurisdiction in finding that it does not have authority to approve the REA-related costs for recovery from FortisAB's own customers under its tariff; and

(b) the AUC erred in law or jurisdiction in finding that even if it had the authority to approve the FortisAB REA-related costs, it would decline to do so as it would be contrary to the public interest.

EQUS' proposed grounds of appeal were that:

(a) the AUC erred in law or jurisdiction in determining and approving FortisAB's calculation of its costs of integrated operations with REAs; and

(b) the AUC erred in law or jurisdiction in ordering that a portion of FortisAB's costs of providing electric distribution service be allocated to and recovered from REA members and that a portion of REA costs of providing electric distribution service to their members be allocated to and recovered from FortisAB's customers.

The AFREA's proposed grounds of appeal were that:

(a) the AUC erred in law or jurisdiction in interpreting the relevant statutory authorities and failed to respect the negotiation and arbitration processes set out in the *Roles, Relationships and Responsibilities Regulation*;

(b) the AUC erred in law or jurisdiction in failing to observe the requirements of procedural fairness by allowing untested facts and improperly limiting argument during the hearing; and

(c) the AUC erred in law or jurisdiction by deciding an issue which was *res judicata*.

<u>ABCA Analysis</u>

The ABCA held that the applications of FortisAB and EQUS underscore that the AUC's decision is capable of being interpreted in many ways and has raised concerns leading to uncertainty as to what was determined, what was intended, the impact going forward and, most importantly, whether it was within the jurisdiction of the AUC.

FortisAB argued that the Decision contradicts subsection 122(2) of the *Electric Utilities Act* ("*EUA*"), as it does not provide for a reasonable opportunity to recover prudently incurred costs and expenses associated with invested capital. FortisAB also submitted that the alternative method of doing so suggested in the Decision - arbitration - was a meaningless exercise.

EQUS submitted that the decision to allow some of the FortisAB costs to be included is beyond the jurisdiction of the AUC and in direct contradiction to the AUC's April 2020 decision, where it held that it did not have the authority to approve the REA Charge as REAs are not "customers" under the *EUA* and that such charges could be addressed through integrated operations agreements or arbitration with the REAs. EQUS argued that costs related to integrated operations are properly dealt with in accordance with the negotiation and arbitration processes in the *Roles, Relationships and Responsibilities Regulation*.

EQUS supported FortisAB's application but sought to broaden the questions to include whether the AUC has any jurisdiction to consider the costs of integrated operations between the electrical utility and an REA.

The ABCA found that the issues raised by FortisAB and EQUS meet the requirements of the test for permission to appeal. The issues raised are of significance to the parties and to the practice and raise arguments that could benefit from appellate review and comment. Permission to appeal was granted to both FortisAB and EQUS on their proposed grounds of appeal.

As the grounds proposed by the AFREA were covered by those put forward by EQUS, the ABCA found it unnecessary and duplicative for the AFREA to have permission to appeal in its own right. The ABCA however noted that if the AFREA wishes to participate in the appeal, it could do so as an intervener.

***TransAlta Corporation v Alberta (Utilities Commission),* 2022 ABCA 37**
Decommissioning Costs - Associated Facilities

In this decision, the Alberta Court of Appeal ("ABCA") majority dismissed TransAlta Corporation ("TransAlta")'s appeal of AUC Decision 23778-D01-2021, where the AUC decided that it was not bound by an arbitration award regarding the decommissioning of Sundance A Generating Units 1 and 2 at the TransAlta Sundance Power Plant (the "Decision").

<u>Background</u>

The Decision arose in relation to TransAlta's application for payment of its remaining uncollected costs to decommission two generating units, Sundance A Generating Units 1 and 2 at the TransAlta Sundance Power Plant (the "Decommissioning Application") from the Balancing Pool. TransAlta asked the AUC to include in those costs a proportionate share of the costs to decommission the Highvale Mine, consistent with how much of the

Highvale Mine product was the fuel source for the Sundance A units. TransAlta and the Balancing Pool had participated in a private arbitration proceeding regarding the Balancing Pool's obligation to pay TransAlta costs of other generating units (Sundance B and C) at the Sundance Power Plant upon the termination of the power purchase arrangements for those units. In that proceeding, the arbitration panel decided that the Highvale Mine was an "associated facility" of the Sundance B and C generating units and TransAlta was entitled to include the proportional costs related to the Highvale Mine in the decommissioning costs for those generating units.

TransAlta wanted the AUC to make a preliminary ruling that the issue of the Highvale Mine being considered an "associated facility" (the "Mine Issue") was *res judicata* so that there would no need for TransAlta to lead evidence on that point. This means the Commission would therefore be bound to extend the arbitration panel's conclusion regarding the Mine Issue to the Sundance A generating units. The AUC rejected TransAlta's position. While making observations that it was not bound by the arbitration decision, the AUC did not say it would necessarily reject the arbitration panel's conclusion in the end.

The Honourable Justice Watson and The Honourable Justice Crighton found that the AUC did not err, and they dismissed the appeal. The Honourable Justice O'Ferrall concurred in the result.

<u>ABCA Approval of Permission to Appeal</u>

The ABCA had granted permission to appeal on the following grounds: did the AUC err in law by failing to conclude that the arbitration award renders the Mine Issue *res judicata* or subject to abuse of process by:

(a) failing to identify and apply the correct legal test?

(b) concluding that the "context" of the Decommissioning Application affects the legal meaning and application of the *Electric Utilities Act* definition of "generating unit"?

(c) failing to provide transparent and intelligible reasons that cogently and logically support the outcome of the ruling?

<u>Positions of the Parties</u>

Role of the AUC on the Appeal

The ABCA noted that a reviewing court will not expect to hear submissions as to "merits" from the tribunal. However, in the unique circumstances of this appeal, the ABCA was satisfied that the AUC should be permitted to defend its legal conclusion on the points of law regarding the interpretation and application of the concept of *res judicata,* but limited its submissions to argument on the existing record.

TransAlta's Position on Appeal

The AUC said it intended "to exercise its discretion to make its own determination on the Mine Issue after the record of this proceeding has closed" and that the AUC did not consider itself "bound by the arbitration panel's ruling" and would "make its own determination as to whether any mine costs are eligible to be included". TransAlta criticized the AUC's ruling for not referring to the legal tests for *res judicata*, issue estoppel, or abuse of process, and for not setting out how the AUC applied those tests to the facts before it. TransAlta also faulted the AUC for not identifying and rationalizing any discretion not to apply *res judicata*, issue estoppel or abuse of process.

Standard of Review

The ABCA noted that the judgment of the Supreme Court in *Canada (Minister of Citizenship & Immigration) v Vavilov*, 2019 SCC 65, seems to have somewhat left open the question whether the existence of a statutory appeal mechanism should always bring into effect the appellate role because there may be other legislative signals in a different direction. The ABCA found that TransAlta's position is that the arbitration award essentially excludes the AUC from any jurisdiction to reach a different conclusion than the arbitration award does. Although the AUC is not a party in the arbitration award, TransAlta argued for a variation on the doctrine and structure of *res judicata* to make the AUC bound by it. In this case, because TransAlta argued that the AUC either was or was not bound by the decision of the arbitration panel, the ABCA determined that the question of whether the reasonableness or the correctness standard of review applied was moot.

Jurisdictional Considerations

The essence of TransAlta's position was that the arbitration award excludes the AUC from any jurisdiction to reach a different conclusion than the arbitration award did. Although in no sense, factual or legal, can the AUC be characterized as being a party (or privy to a party) in the arbitration award, TransAlta contended for a variation on the doctrine and structure of *res judicata* to make the AUC bound by it.

The ABCA did not agree. It found that the AUC took the position that it was not bound by the legal conclusion of the arbitration award as to the definition of individual terms. The AUC may still agree with the award. It may consider and defer to the findings made in it that the decommissioning costs for Sundance A should be, as TransAlta asserts, the same as for Sundance B and C and for the same line of reasoning as set out in the arbitration award.

Did the AUC Err on the Law of Res Judicata?

The ABCA decidedly found that the AUC did not err on the law of *res judicata* because the issue is not governed by the law of res *judicata.*

The ABCA found that the AUC was not required to go into detail about the test for *res judicata*, as argued by TransAlta. The ABCA determined that the crucial decision of the AUC was that it was not required by that law to yield to the arbitration award's interpretation of the legislation in this case.

The ABCA, relying on the legislative intent, particularly regarding the public interest, found it clear that the legislative responsibility in cases such as the present could not be delegated from the AUC as a public regulator to an arbitration panel.

Accordingly, the ABCA determined that the AUC did not err in looking at the big statutory picture and concluding from the situation before it and before the arbitration panel that a summary disposition at this preliminary stage of Proceeding 23778 on an interpretation of the provisions was not required.

Did the AUC Give Sufficient Reasons?

The ABCA noted that deficient reasoning of a tribunal does not grant the ABCA the power to make its own decision. Rather the decision maker is commonly granted a further opportunity to decide. Regardless, the ABCA noted that the AUC's decision was sufficiently clear and complete enough to meet the functional objectives of intelligibility, reviewability, and accountability on the specific points for which permission was granted.

Contrary to TransAlta's arguments, the ABCA determined that there was nothing to suggest that the AUC would not entertain evidence or submissions on the Mine Issue.

TransAlta's submissions suggest that it doubts whether the AUC will give TransAlta natural justice in the future. The ABCA did not see a reason to presume that this would be the case.

Minority Judgment

The Honourable Justice O'Ferrall concurred with the majority in the result but held that the appeal ought to be dismissed because there is no appeal from an interlocutory ruling of the AUC absent exceptional circumstances such as that identified in the Commission's decision dismissing the Balancing Pool's application for a review and variance of a very similar ruling in the same proceeding (see para 78 herein). The exceptional circumstance identified by the Commission, namely “where a party’s ability to participate fairly in the Board’s process would be fundamentally compromised”, is not present on this record. Nor is there any other exceptional circumstance which would call for a departure from the well-established rule.

Conclusion

The ABCA dismissed the appeal.

ALBERTA ENERGY REGULATOR

***New Functionality Moving to OneStop,* AER Bulletin 2022-02**
Enterprise Submissions

On March 3, 2022, the AER released new functionality and updates for the OneStop platform. The AER added three submission types related to Enterprise Submissions to the platform. Industry submitters are now required to submit through OneStop:

(i) Industrial Wastewater and Runoff Reports;

(ii) Annual Disturbance Reports; and

(iii) Regeneration Vegetation Surveys.

Details on other enhancements and fixes were made available in the "What's New in OneStop" document, found on the OneStop landing page under "Enhancements and Fixes".

***Issuance of Amended Subsurface Orders 1C, 3B, 4A, and 5A,* AER Bulletin 2022-03**
Oil and Gas - Wells

On February 28, 2022, the AER amended subsurface orders 1B, 3A, 4, and 5 to align with changes to its regulatory framework for oil and gas well testing (Bulletin 2021-34), coalbed methane control well requirements (Bulletin 2021-29), and well spacing requirements (Bulletin 2021-14).

The AER uses subsurface orders to adapt the regulatory requirements for specific geological zones over specific geographic areas to best suit energy resource development in those areas. However, recent changes to Directive 040: *Pressure and Deliverability Testing Oil and Gas Wells*, Directive 065: *Resource Applications for Oil and Gas Reservoirs*, and the recission of Directive 062: *Coalbed Methane (CBM) Control Well Requirements and Related Matters* has eliminated the need for some of the exemptions granted in previous versions of the subsurface orders.

The amended subsurface orders have been renumbered as 1C, 3B, 4A, and 5A.

ALBERTA UTILITIES COMMISSION

***Alberta Electric System Operator Approval of Proposed Amended Section 501.3 of the ISO Rules,* AUC Decision 26992-D01-2022**
Abbreviated Needs Approvals - ISO Rules

In this decision, the AUC approved amendments to Section 501.3 of the *Independent System Operator* ("ISO") *Rules*, *Abbreviated Needs Approval Process* as applied for by the Alberta Electric System Operator ("AESO") pursuant to subsection 20.2(1) of the *Electric Utilities Act* ("*EUA*").

Since the implementation of Section 501.3 in July 2015, only 13 percent of connection and system projects have satisfied the eligibility criteria for the abbreviated process. The AESO concluded that the criteria in Section 501.3 were too stringent. The proposed amendments expand the existing eligibility requirements. The proposed amendments included:

(a) removing detailed scope-based eligibility requirements for transmission facility projects based on system access service requests and increasing the cost threshold to include all transmission facility projects with up to $25 million in total costs, of which system costs are not expected to exceed $15 million; and

(b) providing a less prescriptive approach with respect to the factors that must be considered prior to approving a project.

<u>Issues</u>

Criteria of Section 20.21

The AUC determined that the proposed amendments to the ISO Rule resulted in a rule that is not technically deficient, supports the fair, efficient, and openly competitive operation of the market to which it relates, and is in the public interest. Therefore, the AUC found that the amended Section 501.3 complies with the requirements of Section 20.21(a) of the *EUA.*

The AUC noted that the proposed amendments maintain a transparent approval process, as notice of all projects under consideration for the process under Section 501.3 will be posted to the AESO's website, and stakeholders are given 14 days to review the projects. As previously stated, the AESO may restrict eligibility if there are significant stakeholder questions or concerns.

Did the AESO Fulfill its Obligation to Adequately Consult with Stakeholders?

The AESO began its consultation process with the initial proposal of the amendments to Section 501.3 in September 2021. The AUC was satisfied with the AESO's consultations and all comments and the AESO's replies to the comments posted on the AESO's website. Stakeholders raised two principal issues.

(a) The eligibility criteria should be further altered

Stakeholders suggested that the proposed eligibility criteria should be driven by limitations of the scope of the project rather than specific dollar figures. Further, stakeholders were concerned that the inclusion of point of delivery substation projects that include higher costs and impact the interconnected electrical system ("IES") more extensively would remove the AUC from the approval process of many connection projects.

The AESO replied that imposing monetary limits allows for a more efficient and flexible approach, as listing specific project scope criteria would be prescriptive and rigid, with excessive regulatory burden and costs associated with it. Because historical costs of point of delivery substation projects exceed $25 million, the AESO noted its expectation that these projects will not be eligible, and the AUC will not be removed from the process. The AESO also pointed out that the amendments will not give it absolute authority. Disputes regarding its decision can be submitted to the AUC under subsection 11.2(4) of the *Transmission Regulation.*

(b) The amendments would impair the ability of a legal owner of an electric distribution system to plan and maintain an appropriate level of service

Stakeholders suggested that the abbreviated process should be limited to point of delivery substation development projects that have a minor impact on the IES because the reliability criteria that align with longer-term distribution plans could cause impairment. The AESO responded that the requirements set out in the proposed amended Section 501.3 align with the AESO's mandate under the *EUA* and the *Transmission Regulation*.

<u>AUC Decision and Order</u>

The AUC was satisfied that the information and consultation requirements established by Rule 017 have been met. The AUC approved the proposed amended Section 501.3 of the ISO Rules, *Abbreviated Needs Approval Process*, to be effective February 9, 2022, the date of this decision.

***Alberta Electric System Operator Approval of Proposed Amended Section 502.9 of the ISO Rules*, AUC Decision 27145-D01-2022**

ISO Rules - Synchrophasor Measurement Units

In this decision, the AUC granted an application for the approval of proposed amendments to Section 502.9 of the *Independent System Operator* ("*ISO*") *Rules*, *Synchrophasor Measurement Unit Technical Requirements* as submitted by the Alberta Electric System Operator ("AESO") pursuant to subsection 20.2(1) of the *Electric Utilities Act* ("*EUA*").

<u>Introduction</u>

Section 502.9 of the *ISO Rules* requires the legal owners of generating units, aggregated generating facilities and transmission facilities to implement a synchrophasor measurement unit that meets Institute of Electrical and Electronics Engineers ("IEEE") standards. Synchrophasor measurement units can measure voltage and current phasors with high resolution. This capability provides online and offline applications in power system operation and planning that can enhance the reliable operation of a bulk electric system.

The proposed amendments ensure that legal owners of generating units, aggregated generating facilities and transmission facilities implementing synchrophasor measurement units in Alberta are aligned with the more recent technical requirements in the IEEE standards documents.

The AUC noted that the 2011 and 2014 IEEE standards adequately capture and reflect the dynamic behavior of resources through synchrophasor measurements, and adherence to them aligns with industry guidelines and North American Electric Reliability Corporation guidelines. However, older measurement devices may not be compatible with the newer standards. Since the AESO has not identified any deficiencies in IEEE Standard 2005, it included legacy treatment for existing facilities that the AESO issued a functional specification for, and which were energized and commissioned between February 28, 2013 and February 28, 2022 inclusive. These facilities will be permitted to continue complying with IEEE Standard 2005 only, in order to mitigate upgrade cost impacts. Regardless of the legacy treatment provision, Section 502.9 permits the AESO, based on its determination of safety or reliability needs, to require facilities that otherwise qualify for legacy treatment to comply with the 2011 and 2014 IEEE standards.

<u>Issues</u>

The AUC determined that the amended *ISO Rule* is not technically deficient and is in the public interest. Regarding the requirement that a rule must support the fair, efficient and openly competitive function of the market to which it relates, the AESO submitted that the costs of requiring existing facilities to comply with the updated standards outweigh the benefits of system reliability. Complying with the 2005 standard does not materially impact system reliability, and the AESO still receives the data it needs. Concerning new units, the AESO assessed that there are no material cost differences between devices compliant with the older or newer standards, meaning that the new units are not disadvantaged by the imposition of higher costs.

The AUC therefore found that the amended Section 502.9 complies with the requirements of Section 20.21(2) of the *EUA.*

Did the AESO Fulfill its Obligation to Adequately Consult with Stakeholders?

During its consultation, AltaLink Management Ltd. raised concerns regarding cost implications for market participants and ratepayers regarding compliance with the 2011 and 2014 IEEE standards. The AESO explained that the legacy treatment provision in the proposed amendments to Section 502.9 was included to ensure that upgrades to measurement devices are not required when not necessary. The AUC was satisfied that the requirements of Rule 017 had been met.

AUC Order

The AUC determined that the proposed amendments to Section 502.9 *Synchrophasor Measurement Unit Technical Requirements* comply with Section 20.21 of the *EUA.* Accordingly, pursuant to *EUA* subsection 20.21(1)(a)*,* the AUC approved the amendments, with effect as of March 1, 2022.

ATCO Electric Ltd., ATCO Energy Ltd. and ATCO Gas (a Division of ATCO Gas & Pipelines Ltd.) Amendments to Code of Conduct Regulation Compliance Plans, **AUC Decision 27005-D01-2022**
CCR Compliance Plan

In this decision, the AUC approved the application from ATCO Electric Ltd., ATCO Gas (a division of ATCO Gas & Pipelines Ltd.), and ATCO Energy Ltd. (collectively “ATCO”) to amend their Code of Conduct Regulation Compliance Plans (“CCR compliance plans”).

On November 12, 2020, the *Code of Conduct Regulation* was amended, necessitating changes to ATCO’s CCR compliance plans. On November 12, 2020, the AUC repealed Rule 030: *Compliance with the Code of Conduct Regulation* which affected the requirements for CCR compliance plans in the following ways:

(a) s. 8 (Meetings between distributors or regulated rate suppliers and retailers and customers), s. 25 (Records and accounts), s. 26 (Written financial transactions), s. 27 (Records of transactions for goods and services), and s. 28 (Maintaining records) was repealed;

(b) s. 33 (Quarterly and annual compliance reports) was amended, removing the requirements to submit quarterly compliance reports to the AUC;

(c) s. 40 (Audits) was amended, reducing the frequency of compliance audits from at least once every 36 months to at least once every 10 years;

(d) s. 41 (Audit report) was amended to exempt small Rural Electrification Associations (fewer than 1,400 members) from the audit requirement; and

(e) the requirement for utilities to report instances of non-compliance within 30 days of discovery was removed.

In order to address the removal of record retention requirements from the *Code of Conduct Regulation*, the AUC issued a letter on July 12, 2021, requiring that utilities retain certain records relevant to audits for a minimum of three years.

Amendments

In addition to amendments related to the sections noted above, ATCO proposed to add provisions to Section 9.0 (Confidentiality of Customer Information) of the CCR compliance plans. The changes to Section 9 were intended to clarify the reporting of privacy breaches that are under the purview of either the Information and Privacy Commissioner or the AUC. ATCO stated that the proposed changes would reduce administrative burden.

The *Code of Conduct Regulation* is concerned with customer information insofar as preventing any single utility from having unequal access to information disclosed by distribution companies.

The AUC agreed with ATCO's proposed revisions to distinguish the reporting and disclosure requirements to the AUC under the *Code of Conduct Regulation* from the reporting requirements governed by the *Freedom of Information and Protection of Privacy Act* and the *Personal Information Protection Act*.

The AUC was satisfied that the amendments proposed to ATCO's CCR compliance plans are consistent with continued compliance with and sufficiently address the Code of Conduct Regulation requirements. Further, the amendments align with the requirements communicated by the AUC following the repeal of Rule 030.

The AUC approved the amended CCR compliance plans as submitted by ATCO, including the proposed additions to Section 9.0 of ATCO's CCR compliance plans.

Balancing Pool Application for an Order Permitting the Sharing of Records Not Available to the Public Regarding the Coaldale Solar Project, **AUC Decision 27162-D01-2022**
Information Sharing - FEOC

In this decision, the AUC approved the application from the Balancing Pool for the preferential sharing of records that are not available to the public pertaining to the electricity and ancillary services markets under Section 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*").

Introduction and Procedural Background

The Balancing Pool filed the application on behalf of Concord Coaldale GP2 Ltd. ("Concord Coaldale"), a small scale power producer. It applied for permission to share records not available to the public between the Balancing Pool (acting in its capacity on behalf of a small scale power producer, under Section 7 of the *Small Scale Generation Regulation*), Concord Coaldale, Concord Coaldale Partnership ("CCP") and URICA Energy Real Time Ltd. ("URICA") relating to the 22-megawatt Coaldale Solar Project, located near the town of Coaldale.

AUC Findings

Section 7 of the *Small Scale Generation Regulation* states that "unless…request[ed] otherwise, the Balancing Pool (a) must act as the electricity market participant on behalf of the small scale power producer in dealings with the Independent System Operator in respect of the electric energy supplied by the small scale power producer's small scale generating unit." The AUC held that Concord Coaldale qualifies as a small scale power producer and is therefore represented as an electricity market participant by the Balancing Pool.

Subsection 3(3) of the *FEOC Regulation* authorizes 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 are satisfied. The AUC found that those requirements were met.

The AUC was satisfied that the Balancing Pool had demonstrated that (i) the sharing of records with URICA was reasonably necessary for the Balancing Pool 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 the Balancing Pool and written representations from Concord Coaldale and CCP, the AUC was satisfied that the Balancing Pool, Concord Coaldale and CCP, and URICA would conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market.

The total offer control percentages of Balancing Pool, Concord Coaldale and CCP, and URICA are below the maximum of 30 percent, set out in subsection 5(5) of the *FEOC Regulation.*

Given the mandate of the Market Surveillance Administrator ("MSA") 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.

***Balancing Pool Application for an Order Permitting the Sharing of Records Not Available to the Public Regarding the East Strathmore Solar Power Plant,* AUC Decision 27121-D01-2022**
Market Oversight and Enforcement - FEOC

In this decision, the AUC approved the application from the Balancing Pool for the preferential sharing of records that are not available to the public pertaining to the electricity and ancillary services markets under Section 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*").

Introduction and Procedural Background

The Balancing Pool filed an application seeking permission to share records not available to the public between the Balancing Pool (acting in its capacity on behalf of a small scale power producer, under Section 7 of the *Small Scale Generation Regulation*), East Strathmore Solar Project Inc. ("East Strathmore SP"), Elemental Energy Inc. ("Elemental"), Elemental Energy Renewables Inc. ("Elemental Renewables") and URICA Energy Real Time Ltd. ("URICA") relating to the 20.1-megawatt East Strathmore Solar Power Plant located in Wheatland County.

AUC Findings

Section 7 of the *Small Scale Generation Regulation* states that "unless…request[ed] otherwise, the Balancing Pool (a) must act as the electricity market participant on behalf of the small scale power producer in dealings with the ISO in respect of the electric energy supplied by the small scale power producer's small scale generating unit." The AUC held that East Strathmore SP qualifies as a small scale power producer and is therefore represented as an electricity market participant by the Balancing Pool.

Subsection 3(3) of the *FEOC Regulation* authorizes 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 are satisfied. The AUC found that those requirements were met.

The AUC was satisfied that the Balancing Pool had demonstrated that (i) the sharing of records with URICA was reasonably necessary for the Balancing Pool 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 the Balancing Pool and written representations from all parties, the AUC was satisfied that the Balancing Pool, East Strathmore SP, Elemental, Elemental Renewables 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 total offer control percentages of Balancing Pool, East Strathmore SP, Elemental, Elemental Renewables and URICA are below the maximum of 30 percent, set out in subsection 5(5) of the *FEOC Regulation.*

Given the mandate of the Market Surveillance Administrator ("MSA") 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.

***Bull Trail Renewable Energy Centre PG Inc. Bull Trail Wind Power Project,* AUC Decision 26981-D01-2022**
Wind Power - Facilities

In this decision, the AUC approved the application from Bull Trail Renewable Energy Centre GP Inc. ("Bull Trail Energy") to construct and operate the 270-megawatt ("MW") Bull Trail Wind Power Project (the "Project").

Application

Bull Trail Energy applied for approval to construct the Project, consisting of 51 turbines on 5,917 hectares of private and primarily cultivated lands near the hamlet of Irvine in Cypress County. Bull Trail Energy applied for permission to construct and operate the Project only. The AUC noted that the associated substation and interconnection application would be filed separately.

Bull Trail Energy had not finalized the turbine vendor, model, or layout but submitted the number, capacity, and size would not be changed. As required by Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*, the selection would be finalized no later than 90 days before construction-start.

The application included a noise impact assessment, shadow flicker analysis report, and a summary of the site-specific emergency response plan. Bull Trail Energy also submitted a participant involvement program summary detailing its consultation with stakeholders, a renewable energy referral report from Alberta Environment and Parks ("AEP"), and an environmental evaluation and conceptual conservation and reclamation plan.

Bull Trail Energy expects to start construction on August 1, 2022, with an in-service-date of September 30, 2023. To allow for any unforeseen delay Bull Trail Energy applied for a completion date of December 30, 2024.

Discussion and Findings

The AUC found that the application provides all information required by Rule 007. It noted that the participant involvement program satisfies the requirements of Rule 007 and the objectives of consultation. The AUC found that the noise impact assessment indicated conformance with Rule 012: *Noise Control.* Regarding Receptor R20, the AUC noted that the predicted nighttime cumulative sound level is 40.3 dBA, which exceeds the nighttime permissible sound level ("PSL") of 40 dBA. Pursuant to Section 2.7(6) of Rule 012, the applicant can round predicted cumulative sound levels to the nearest whole number before comparing predicted cumulative levels to the applicable PSLs, which, in this case, results in the sound level abiding by Rule 012.

Since the predicted sound levels slightly exceed the PSL at four receptors, the AUC imposed as a condition of approval that Bull Trail Energy complete a post-construction comprehensive sound level survey to verify compliance with Rule 012 once the Project comes into operation.

AEP found that the Project will pose a moderate risk to wildlife and wildlife habitat considering the location and commitments to mitigate disturbances and mitigate and monitor wildlife impacts. AEP most notably indicated that the Project poses a high risk for bird and bat mortality. The AUC found that further mitigation measures committed to by Bull Trail Energy following consultation with AEP address all environmental information requirements of Rule 007. The AUC was satisfied that diligent implementation of mitigation measures would lead to a reduction of the risks to an acceptable level. To ensure continued compliance and mitigation, the AUC imposed as a condition of approval that Bull Trail Energy submitted to AEP and the AUC annual post-construction monitoring survey reports pursuant to Rule 033: *Post-Approval Monitoring Requirements for Wind and Solar Power Plants.*

As a final condition of approval, Bull Trail Energy is required to file a final project update with the AUC once equipment selection is finalized to confirm that the Project stays within the final project update specified allowances for wind power plants. Bull Trail Energy was directed to file the final project update at least 90 days prior to the start of construction.

Decision

Pursuant to Section 11 of the *Hydro and Electric Energy Act,* the AUC approved the application to construct and operate the Project.

***Capital Power Corporation Complaint Application Regarding FortisAlberta Inc. Strathmore Area Interconnection Issues,* AUC Decision 26510-D01-2022**
Distribution-Connected Generation - Interconnection Costs

In this decision, the AUC dismissed the complaint from Capital Power Corporation ("Capital Power") against FortisAlberta Inc. ("FortisAB") regarding charges to interconnect Capital Power's Strathmore Solar Generation Project ("Strathmore Project") with FortisAB's electric distribution system.

Background

Due to increased load on an AltaLink Management Ltd. ("AML") transmission line from additional generation in the area, an underbuilt distribution line owned and operated by FortisAB is expected to experience clearance violations with the transmission line. As part of its interconnection process, FortisAB charged Capital Power $1.33 million in interconnection charges for work to relocate portions of the underbuilt distribution line. In its complaint, Capital Power argued that under FortisAB's Customer Terms and Conditions of Service for Electric Distribution Service ("T&Cs"), it is not appropriate for FortisAB to collect the underbuilt costs from Capital Power.

The Strathmore Project is a 40.5-megawatt ("MW") solar generation power plant that will interconnect with FortisAB's distribution system through two distribution lines. These distribution lines connect to AML's Strathmore 151S Substation.

FortisAB's T&Cs require a distribution-connected generation ("DG") customer, such as Capital Power, to pay certain interconnection costs, including the work FortisAB and, in this case, AML has to do to connect the project. The amount paid by Capital Power to FortisAB is not in dispute. In addition to the interconnection costs, FortisAB levied $1.33 million in underbuilt costs against Capital Power. Capital Power disputes the appropriateness of these costs.

The Strathmore 151S Substation connects to the Chestermere 419S Substation through AML's Transmission Line 765L. At various segments along this transmission line, FortisAB has distribution lines that are underbuilt on the transmission line. The AML transmission line's capacity is currently limited as a result of the separation between it and these underbuilt distribution lines. When loading on the transmission line increases, the temperature of its conductors likewise increases, causing the conductors to sag more. This reduces the clearance between the transmission and distribution conductors. The clearances that must be maintained between transmission and distribution conductors are dictated and governed by the Alberta Electric Utility Code.

Interconnection of some DG projects require that the Alberta Electric System Operator's ("AESO") Behind the Fence process be initiated to assess and address any modifications or upgrades required to the transmission system to interconnect the project. As part of this process, the AESO determined that the connection of additional generation in the Strathmore planning area may cause the loading of transmission line 765L to exceed its present ratings.

While the obligation to increase the transmission line's rating falls on AML, FortisAB and AML determined that the optimal solution to increase the rating of Transmission Line 765L would be to relocate the underbuilt distribution lines off of the transmission line. It is these costs to remove and relocate the distribution lines that are disputed by Capital Power in its application.

Necessity of Relocation and Cost Determination

It is the AESO's obligation to plan the transmission system and to direct its safe, reliable and economical operation. The AESO may issue transmission system-related functional specifications that detail the technical specifications for the design, construction, development and commissioning of any generation project.

The AESO informed AML that additional generation connecting in the Strathmore/Blackie planning area had exceeded the 40-MW threshold and that the rating of Transmission Line 765L needed to be increased.

FortisAB and the AESO use different criteria to determine the allocation of the costs that result from exceeding the rating of a transmission line because of the connection of planned additional generation. Under the AESO's criteria, it was a project owned by Elemental Energy Inc. ("Elemental Energy") that resulted in the exceedance of the threshold. Under FortisAB's criteria, Elemental Energy secured its position before Capital Power, as a result of which, FortisAB chose to allocate the costs for the relocation to Capital Power.

FortisAB considered that the $1.33 million underbuilt costs qualify as interconnection costs under its T&Cs and that Capital Power is responsible for paying the entirety of the underbuilt costs due to its position in FortisAB's DG queue.

Summary of Complaint and Procedural Background

The primary argument brought by Capital Power in its complaint was that the underbuilt costs did not qualify as "interconnection charges" under FortisAB's T&Cs. Capital Power accordingly sought an order directing FortisAB to retract the quotation package and invoice it had presented to Capital Power for the underbuilt costs, and a refund for the underbuilt costs Capital Power paid, along with interest.

Following an application filed by Capital Power with its complaint, the AUC had issued an order indicating that any payment to FortisAB of the underbuilt costs at issue is to be made interim and subject to adjustment on the final determination.

Issues

Underbuilt Costs Qualify as "Interconnection Charges" Under FortisAB T&Cs

The AUC noted that its role in a complaint proceeding regarding T&Cs is limited to ensuring that the T&Cs are being interpreted and applied in accordance with the principles of statutory interpretation. The AUC confirmed that it viewed the T&Cs between a public utility and its customers as "legally imposed regulations that bind the utility to provide a service at just and reasonable rates to all who require and demand them".

The AUC determined that Section 12.6.1 - *Interconnection Charges* requires interpretation. The AUC further considered the definitions set out in the T&Cs. Capital Power submitted that the underbuilt costs are not "interconnection charges" because they are not charges that would allow the DG customer to make use of the electric distribution system, as is required by Section 12.6.1. Capital Power argued that the costs are, on the contrary, required to relieve a long-standing transmission constraint.

The AUC disagreed and found that, on a plain reading, the scope of "interconnection charges" is inclusive of all incremental interconnection costs that would allow the DG customer to make use of the electric distribution system. In the case of this complaint, the AUC agreed with FortisAB that use of the electric distribution system is inextricably linked with access to the transmission system. Further, contrary to the arguments from Capital Power, the AUC determined that underbuilt costs fit within the definition of interconnection facilities, as these include "all modifications required for interconnection which may include, without limitation, poles, lines, substations, service leads, and protective and metering equipment."

The AUC found that the requirement to remove the underbuilt distribution line and the associated underbuilt costs are contemplated within the language of FortisAB's T&Cs. For that reason, the underbuilt costs qualify as interconnection charges.

FortisAB's DG Queue Practices Determine the Allocation of the Underbuilt Costs

FortisAB determined Capital Power's cost responsibility for the underbuilt costs in accordance with its DG queue practices. To manage DG applications for interconnection, FortisAB employs the DG queue process. The DG queue is used to guide the allocation of upgrade costs in circumstances where the capability of existing infrastructure to accommodate the interconnection of DG projects at their specific requirements has been or will be used by earlier queue entrants. The process is based on a "first come, first served" model.

Capital Power argued that FortisAB's DG queue practices arbitrarily assign the costs of a system upgrade to a certain project even though the energization of that project may not ultimately drive the requirement for the upgrade. At the same time, a project that secured its position in the DG queue earlier may avoid any cost responsibility for an upgrade more properly attributable to it. Capital Power argued that the AESO's project inclusion criteria to allocate and assign the costs for the underbuilt work would best reflect cost causation and avoid undue and arbitrary discrimination.

The AUC determined that FortisAB is entitled to rely on its DG queue to allocate the underbuilt costs in this case. The AUC based this on the determination that T&Cs approved by the AUC reasonably entitle FortisAB to charge the underbuilt costs to Capital Power under the same provisions that give FortisAB the discretion and authority to determine such costs. Further, the DG queue practices are based on a "first come, first served" basis. Accordingly, the DG proponent secures its position in the DG queue once high-level study fees are paid. Following further submissions by FortisAB, the AUC concluded that any costs required to interconnect that arise after a DG proponent has paid its high-level study fees must be borne by the subsequent DG proponent.

The AUC accepted that FortisAB's DG queue practices are not unduly or arbitrarily discriminatory in the sense that they are available to and known by all DG proponents and therefore contain an element of transparency.

The AUC noted that it might be useful for future projects if FortisAB incorporated into its practices a mechanism that specifically contemplates the potential sharing of information and any interconnection costs amongst DG proponents proposing to interconnect in the same area within a similar timeframe, where the benefits associated with any such costs will be enjoyed by parties other than the specific party that triggers them.

Order

The AUC dismissed the complaint filed by Capital Power, and the underbuilt costs and any necessary adjustments are to be paid by Capital Power to FortisAB on a final basis.

***City of Lethbridge 2021-2023 Transmission Facility Owner General Tariff Application,* AUC Decision 26554-D01-2022**

General Tariff Application- Revenue Requirement

In this decision, the AUC considers the general tariff application ("GTA") from the City of Lethbridge Electric Utility ("Lethbridge"). Lethbridge is a transmission facility owner ("TFO") under the *Electric Utilities Act*. In the GTA, Lethbridge sought AUC approval of its revenue requirement to provide transmission service for 2021, 2022 and 2023.

2021-2023 GTA

In its GTA, Lethbridge applied for revenue requirements of $9.295 million, $9.312 million and $9.719 million for 2021, 2022 and 2023, respectively. Lethbridge also requested AUC approval of the reconciliation and continuation of its deferral and reserve accounts and compliance with previous AUC directions.

Compliance with AUC Directions

The AUC found that Lethbridge has complied with the requirements of directions 5, 6 and 12 from Decision 21213-D01-2016, which remained outstanding. Pursuant to the directions, Lethbridge was required to make specific adjustments to its depreciation studies, to conduct analyses of assets in different accounts, to use uniform account names across its next depreciation study and minimum filing requirement schedules, and to include various information about new depreciation parameters. The AUC also found that directions 4, 5, 7 and 8 from Decision 24847-D01-2020 had been complied with. Directions 4 and 8 of Decision 24874-D01-2020, required Lethbridge to make improvements to its tracing of municipal corporate expenses, to use AUC approved depreciation parameters and to prepare intervening parties for the next GTA in a workshop no later than three months prior to its filing.

Should the AUC Approve Lethbridge's Redesigned Minimum Filing Requirement Schedules?

Lethbridge redesigned its Minimum Filing Requirements (”MFR”) schedules for this application to facilitate the finding and interpretation of information, eliminate repeated information, minimize redundancy, and improve regulatory efficiency.

The AUC was of the view that the redesigned MFR schedules did not achieve their desired effect and were confusing. Lethbridge departed from the standardized organization of MFR schedules that applies to all electric transmission utilities in Alberta. The AUC was generally concerned with the consistency of information provided by Lethbridge and repeated that the onus is on the applicant to provide complete and clear information to avoid having costs disallowed.

While the AUC approved Lethbridge's redesigned MFR schedules as filed, the AUC directed Lethbridge not to make further changes to its MFR schedules in the future, unless specifically directed by the AUC.

Should the AUC Direct any Changes to Lethbridge's Forecasting Methodology for Operating Costs, and is any Disallowance Required for the 2021-2023 Test Period?

Interveners to this proceeding took issue with the simplistic method to forecasting operation and maintenance (“O&M”) expenses, arguing that it failed to incorporate current and available information and did not explain cost variances. The AUC approved Lethbridge's forecasting methodology used in this application, as well as forecast operating costs as filed, but instructed Lethbridge that, in future GTAs, all forecast dollar amounts must be reasonably supported, irrespective of the forecast methodology used.

Is Lethbridge's Forecast Depreciation Expense Reasonable?

(a) Lethbridge's proposed net salvage procedure

The AUC's direction in Decision 21213-D01-2016 and 24847-D01-2020 led Lethbridge to conclude that its municipal depreciation practices were not compatible with the AUC's expected methods for ratemaking. Lethbridge has taken steps to reconcile its municipal depreciation practices and the AUC's expected methods for ratemaking. The AUC accepted the proposal to implement a single “accumulated net salvage account” as opposed to an asset retirement obligation. The AUC directed that this single account be treated like Lethbridge's accumulated depreciation accounts, where the account balances inform the rate base.

(b) Depreciation parameters proposed by Lethbridge in its depreciation study

In 2022 and 2023, the amortization of reserve differences true-up continued to reduce forecast depreciation expense, as they had from 2020 to 2021. Significant forecast capital additions in the amounts of $9.4 million and $4.9 million, respectively, were offset by forecast asset retirements in the amounts of $2.5 million and $1.7 million. However, in 2023 depreciation expense increased over the previous year. The depreciation rates were calculated on the basis of using a straight-line depreciation method, an equal life group procedure, and applied on a whole life basis.

The AUC examined Lethbridge's depreciation study in support of its proposed changes to life-curve depreciation parameters for each of its transmission plant accounts. The AUC approved all life-curve changes proposed, excluding Uniform System of Account ("USA") 356.00, as it found that the changes are reasonable, supported by the depreciation study and the retirement rate analysis included therein.

The AUC denied Lethbridge's proposed -45 percent net salvage for USA 356.00 – Transmission Lines. The AUC noted that Lethbridge's currently approved -40 net salvage percent is within the -25 to -90 percent range of its peer utilities. Further, no salvage costs that could provide support for an increase to -45 percent have been incurred for this account since the time of its previous depreciation study. The AUC approved net salvage of -40 percent for USA 356.

Lethbridge reported differing December 31, 2019, book balances between its depreciation study and MFR schedules. The AUC directed Lethbridge to explain this difference.

The AUC accepted Lethbridge's method of accounting for any USA account subject to amortization accounting and the use of an SQ curve; and approved Lethbridge's inclusion of costs related to its 2019 depreciation study in its transmission tariff, but directed Lethbridge to include such costs as part of its costs claim application going forward.

Should the AUC Approve Lethbridge's Forecast Fleet Capital Additions?

Lethbridge applied for approval of forecast capital additions of $201,000 for 2022 and $135,000 for 2023. The vehicle fleet is allocated to the transmission function based on the number of hours the vehicle was used to work on transmission projects. While the AUC was able to reconcile the forecast capital additions of the vehicles in 2022 and 2023, it observed inconsistencies and was unable to identify several of the vehicles Lethbridge stated were to be replaced.

The AUC approved Lethbridge's transmission function fleet capital additions, conditional thereon that Lethbridge provide, in the compliance filing, clarifications necessary to address the AUC's observation and provide evidence to adequately support that fleet vehicles are required to be replaced.

Order

The City of Lethbridge is required to file its 2021-2023 transmission GTA by March 7, 2022, to address the issues noted by the AUC in its decision.

***Conrad Solar Inc. Application for an Order Permitting the Sharing of Records not Available to the Public Regarding the Wrentham Solar Project,* AUC Decision 27146-D01-2022**

Market Oversight and Enforcement - FEOC

In this decision, the AUC approved the application from Conrad Solar Inc. ("Conrad Solar") for the preferential sharing of records that are not available to the public, pertaining to the electricity and ancillary services markets under Section 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*") between Conrad Solar and URICA Energy Real Time Ltd. ("URICA").

Introduction and Procedural Background

Conrad Solar filed an application seeking permission to share records not available to the public between Conrad Solar and URICA relating to the planned Wrentham Solar Project (the "Project"), located in the County of Warner. The Project will consist of 90,325 solar photovoltaic panels and have a total generating capability of 41.4 megawatts.

AUC Findings

Subsection 3(3) of the *FEOC Regulation* authorizes 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 are satisfied. The AUC found that those requirements were met.

The AUC was satisfied that Conrad Solar had demonstrated that (i) the sharing of records with URICA was reasonably necessary for Conrad Solar 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 Conrad Solar and written representations from URICA, the AUC was satisfied that Conrad Solar 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 total offer control percentages of Conrad Solar and URICA are 0.6 percent. The total is below the maximum of 30 percent, set out in subsection 5(5) of the *FEOC Regulation.*

Given the mandate of the Market Surveillance Administrator ("MSA") 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 granted the application for sharing of records.

***Enerfin Energy Company of Canada Inc. Winnifred Wind Power Project,* AUC Decision 26504-D01-2022**
Wind Power - Facilities

In this decision, the AUC approved the applications from Enerfin Energy Company of Canada Inc. ("Enerfin") for permission to construct and operate the 122.32-megawatt ("MW") Winnifred Wind Power Plant (the "Power Plant") and a collector substation designated as the Holsom 1054S Substation (collectively, the "Project").

Applications

The Power Plant will consist of 22 Enercon 5.56-MW wind turbines with a hub height of 114 meters and a rotor diameter of 160 meters. The Power Plant will also include access roads, an underground collector system, an operations and maintenance building, and a permanent meteorological tower.

The Project will be constructed on approximately 7,440 acres of privately owned land, approximately 5.5 kilometers north of Whitla in the counties of Forty Mile and Cypress.

AUC Findings

The AUC determined that the applications met the information requirements set out in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines.* The AUC was further satisfied that the participant involvement program met the requirements of Rule 007 and that the Power Plant abided by Rule 012: *Noise Control*.

Enerfin's shadow flicker assessment considered the Project's potential effects at 21 dwellings. The AUC accepted the assessment's conclusion that there would be minimal potential for shadow flicker effects on all receptors.

Alberta Environment and Parks ("AEP") report concluded that the project was sited to avoid known wildlife features, but assessed the risk to raptor nests, sharp-tailed grouse leks, and burrowing owl dens as high due to outdated surveys. Enerfin stated that it intends to update its raptor nest, sharp-tailed grouse lek, and burrowing owl surveys during the next survey season (spring of 2022) and confirmed that it would submit an updated environmental protection plan incorporating additional mitigations. The AUC imposed, as a condition of approval, that Enerfin either submits an updated environmental protection plan to the AUC that incorporates any additional mitigations proposed as a result of the new surveys, or provide confirmation that no new wildlife features were identified by the new surveys and no additional mitigation is required. Enerfin is required to provide this information no later than 60 days before the scheduled start of construction.

As a further condition of approval, the AUC required Enerfin to submit a post-construction monitoring survey report to AEP and the AUC within 13 months of the Project becoming operational, and on or before the same date every subsequent year for which AEP requires surveys pursuant to subsection 3(3) of Rule 033: *Post-Approval Monitoring Requirements for Wind and Solar Power Plants.*

<u>AUC Decision</u>

Pursuant to sections 11, 14, 15 and 19 of the *Hydro and Electric Energy Act,* the AUC approved the applications to construct and operate the Power Plant and substation.

EPCOR Energy Alberta GP Inc. 2021-2022 Non-Energy Regulated Rate Application, **Decision 26694-D01-2022**

Negotiated Settlement Agreement - Revenue Requirement

In this decision, the AUC approved the 2021-2022 negotiated settlement agreement ("NSA") for EPCOR Energy Alberta GP Inc. ("EPCOR")'s 2021-2022 non-energy regulated rate tariff ("RRT"). EPCOR, the Consumers' Coalition of Alberta ("CCA") and the Office of the Utilities Consumer Advocate ("UCA") are signatories to the NSA.

The NSA did not address two issues, as they were not settled in negotiations:

- Amounts from March 18, 2020, to June 18, 2020, included in EPCOR's COVID-19 deferral account. The AUC directed EPCOR to revise its COVID-19 deferral account to exclude the COVID-19 amounts from March 18, 2020, to June 18, 2020, and to reflect a credit of $130,000 to EPCOR's customers.

- The forecast credit costs included as part of EPCOR's non-energy revenue requirement. The AUC directed EPCOR to exclude credit costs of $0.69 million for 2021 and $0.70 million for 2022 from its revenue requirements.

The NSA, excluding the unresolved issues, resulted in reductions to EPCOR's applied-for revenue requirement of $3.75 million in 2021 and $1.83 million in 2022, or 8.0 percent and 4.4 percent, respectively.

<u>Summary of the NSA</u>

In the application for approval of the NSA, EPCOR forecast RRT allocated costs of $46.65 million in 2021 and $41.85 million in 2022. Beyond the adjustments to the RRT revenue requirement, the parties agreed that for 2022, the AUC should approve deferral accounts for late payment charges, retail connection fees, and bad debt.

The bad debt deferral account was agreed to include a risk-sharing mechanism that requires EPCOR to refund 75 percent of the difference between the actual bad debt expense and $5,460,000 to customers under EPCOR's next non-energy RRT if the bad debt expense is less than $5,460,000. If EPCOR's bad debt expense is greater than $5,460,000, but less than $6,500,000, EPCOR will recover 75 percent of the difference between the actual bad debt expense and $5,460,000 from customers. If EPCOR's bad debt expense exceeds $6,500,000, EPCOR will recover 75 percent of $1,040,000, and EPCOR will also recover 50 percent of the difference between actual bad debt expense and $6,500,000 from customers in EPCOR's next non-energy RRT.

<u>Statutory and Rule Requirements for Approval of an NSA</u>

NSAs are subject to Section 132(1)(a) of the *Electric Utilities Act* ("*EUA*") and AUC Rule 018: *Rules on Negotiated Settlements.* The negotiated settlement process ("NSP") serves to provide a less complicated and less costly alternative to traditional regulation. However, the AUC retains the jurisdiction and obligation to protect the public interest to ensure the process leading to the NSA is fair and reasonable. Further, the NSP does not replace a review by the AUC to determine what is in the public interest. The AUC also maintains discretion regarding the control of rates.

AUC Evaluation of the NSA

The AUC will approve negotiated settlements if it is satisfied that the process resulting in the NSA was fair, and that the NSA serves the public interest.

Is the NSA in the Public Interest, Including Whether or Not it Will Result in Rates that are Just and Reasonable?

The AUC determined that the NSP met the requirements set out in Rule 018. Section 8(2) of Rule 018 requires that the AUC intervenes if it determines that a unanimous settlement is against the public interest. In determining if this is the case, the AUC considered whether the NSA would lead to just and reasonable rates.

The NSA represents a unanimous agreement reached through a negotiation process involving both the CCA and the UCA that collectively represent the interests of a majority of EPCOR's RRT customers. The AUC noted that the NSA resulted in reductions to EPCOR's applied-for revenue requirement of $46.65 million in 2021 and $41.85 million in 2022 by approximately $3.75 million in 2021 and $1.83 million in 2022, or 8.0 percent and 4.4 percent, respectively. The AUC was persuaded that the NSA would lead to rates that are just and reasonable and is not contrary to the public interest

Excluded Matters Outside of the NSA

(a) Should the AUC approve EPCOR's applied-for COVID-19 deferral account, including deferral amounts between March 18, 2020, and June 18, 2020?

The AUC approved EPCOR's COVID-19 deferral account for recovery of amounts between June 19, 2020, and December 31, 2020. As a result of the inclusion of amounts from this period, rather than the period from March 18, 2020, to June 18, 2020, the total COVID-19 deferral account amount approved will reflect a balance of $130,000 to the credit of customers.

In the AUC approved NSA, the parties agreed that the deferral account amounts from June 19, 2020, to December 31, 2020, will be included in the revenue requirement. EPCOR argued that the deferral account amounts from March 18, 2020, to June 18, 2020, were driven by COVID-19 and the start of the Utility Payment Deferral Program ("UPDP") deferral period. As a result, EPCOR argued that these amounts should also be included in the COVID-19 deferral account.

EPCOR's forecast non-energy costs for 2020 were approved on a final basis for the COVID-19 pandemic, and the forecast costs did not take account of costs that would be incurred because of the pandemic. EPCOR argued that notwithstanding the presumption against retroactive ratemaking, its final forecast costs should be increased because of the knowledge exception to the rule against retroactive ratemaking.

The AUC denied EPCOR's request to include costs from March 18 to June 18, 2020. The AUC noted that the announcement from the Government of Alberta from March 18, 2020, regarding the COVID-19 pandemic and the AUC's Bulletin 2020-08 of the same date gave notice that the legal and regulatory framework may change to give effect to the allowable costs recovered under the UPDP, and not to costs excluded from recovery under the UPDP.

(b) Should the AUC approve EPCOR's applied-for non-energy credit costs?

EPCOR's application included a request to recover $0.69 million and $0.70 million in non-energy credit costs associated with providing financial security to the distribution system for 2021 and 2022, respectively. EPCOR confirmed that the methodology for these costs has not changed from previous applications, and the costs related to maintaining the forecast net financial security amounts to EPCOR Distribution and Transmission Inc. ("EDTI") and FortisAlberta Inc. ("FortisAB").

In Decision 24839-D01-2019, the AUC approved the arrangement between EEA and FortisAB for EEA to provide regulated rate option ("RRO") service in the FortisAB distribution service area, including the provision on the posting of financial security.

The UCA raised the concern that the recovery of these costs paid to the distribution utilities is contrary to applicable rules, specifically Section 8(1) of the *Distribution Tariff Regulation.* The UCA argued that the provision of security outlined in Section 8(1) applies to retailers and that EPCOR is an RRO provider, not a retailer, in the context of Section 8(1). It further submitted that the credit costs are not necessary to provide RRO service and should be removed from EPCOR's revenue requirement.

The AUC interpreted the applicable sections of the *EUA* and the *Distribution Tariff Regulation* as only requiring the security deposits from retailers and not regulated rate providers.

EPCOR relied on its obligation as an RRO provider to provide financial security, set out in the terms and conditions of EDTI and FortisAB. The AUC determined that the terms and conditions of service impose a requirement on EPCOR as an RRO provider to pay a security requirement that is inconsistent with legislative requirements in the *EUA* and the *Distribution Tariff Regulation*. As a result of this finding, the AUC encouraged EEA, in discussions with distribution utilities, to amend the agreement and/or apply to the AUC for approval of an amendment of the arrangements of RRO service from Decision 24839-D01-2019.The AUC concluded that Section 8 of the *Distribution Tariff Regulation* does not apply to RRO providers and that such a security deposit does not conform with the plain meaning of a retailer in the *EUA* and the financial security provisions that apply to retailers in Section 8 of the *Distribution Tariff Regulation*. EPCOR was directed to exclude $0.69 million for 2021 and $0.70 million for 2022 related to credit costs from its revenue requirement for 2021-2022.

Compliance with Previous Directions

The AUC was satisfied that EPCOR had complied with all outstanding directions.

Order

The AUC approved EPCOR's NSA for the 2021-2022 non-energy related rate tariff, as filed. The requests to include in EPCOR's revenue requirement COVID-19 costs between March 18, 2020, and June 18, 2020, and non-energy credit costs were denied.