REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

This monthly report summarizes matters under the jurisdiction of the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission (the "AUC" or "Commission") 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 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. RLC follows a team approach, including when working with our clients and industry experts. Visit our website to learn more about RLC.

IN THIS ISSUE:

SUPREME COURT OF CANADA

Canada (Minister of Citizenship and Immigration) v. Vavilov (2019 SCC 65)

Administrative Law - Standard of Review

In this case, a 7-2 majority of the Supreme Court of Canada (the "Supreme Court") revised the rules that govern the standard of review, and provided additional guidance in conducting a reasonableness review.

The Supreme Court noted that reasonableness will be the presumptive applicable standard in all cases. It can be rebutted in two types of situations:

1. Where the legislature has indicated that it intends a different standard to apply. This will be the case where the legislature explicitly prescribes an applicable standard of review, or where the legislature has provided a statutory appeal mechanism from an administrative decision to a court, thereby signalling the legislature's intent that appellate standards should apply.
2. Where the rule of law requires that the standard of correctness should be applied. This will include cases that involve certain categories of questions, namely constitutional questions, general questions of law of importance to the legal system as a whole, and questions related to the jurisdictional boundaries between two or more administrative bodies.

The Supreme Court also provided guidance on conducting a reasonableness review. It noted the importance of coherent reasoning which justifies the outcome of a decision. It is the reasoning that must be the focus, rather than just the conclusion. The exercise of public power must be justified, intelligible and transparent, not only in the abstract, but to the individuals subject to it.

The Supreme Court further noted that a reasonable decision is justified in light of the legal and factual constraints that bear on the decision. These include:

(a) the governing statutory scheme;

(b) other statutory or common law;

(c) principles of statutory interpretation;

(d) evidence before the decision maker;

(e) submissions of the parties; and

(f) past practices and past decisions.

The Supreme Court then went on to apply the reasonableness standard to the *Vavilov* case. Mr. Vavilov was born in Canada. When he was 16 years old, he learned that his parents were Russian spies after they were arrested in the United States. At the time that they lived in Canada, Mr. Vavilov's parents did not have any diplomatic status.

The Canadian Registrar of Citizenship cancelled Mr. Vavilov's certificate of citizenship, noting that his parents were "employees or representatives of a foreign government", and that under section 3(2)(a) of the *Citizenship Act,* citizenship by birth does not apply if either parent was "a diplomatic or consular officer or other representative or employee in Canada of a foreign government."

The Supreme Court found the decision of the Registrar to be unreasonable, noting that the decision was not justified in light of constraints imposed by the text of section 3 of the *Citizenship Act* considered as a whole, by other legislation and international treaties that inform the purpose of s. 3, by the jurisprudence on the interpretation of s. 3(2)(a) and by the potential consequences of her interpretation. Each of these elements - viewed individually and cumulatively - strongly supported the conclusion that s. 3(2)(a) was not intended to apply to children of foreign government representatives or employees who had not been granted diplomatic privileges and immunities.

Bell Canada v. Canada (Attorney General) (2019 SCC 66)

Administrative Law - Standard of Review

In this case, the same 7-2 majority in *Vavilov* applied the new standard of review framework to an appeal of a Canadian Radio-television and Telecommunications Commission ("CRTC") order (the "Order"). The CRTC had issued the Order which Order banned simultaneous ad substitution for the Super Bowl, thereby allowing Canadians to see the high-profile commercials that are part of the broadcast. The Federal Court of Appeal had dismissed appeals of the Order. The 7-2 majority of the Supreme Court of Canada (the "Supreme Court") allowed the appeals, and quashed the Order.

The majority began by noting that the main question under appeal was whether the CRTC had the authority under section 9(1)(h) of the *Broadcasting Act* to issue the Order. While the Federal Court of Appeal had applied a standard of reasonableness, noting the need for deference to the CRTC in its interpretation of its home statute, following *Vavilov,* the Supreme Court majority found that a standard of correctness applied. The majority reached this conclusion by noting that there was a statutory appeal mechanism in the *Broadcasting Act,* meaning that appellate standards of review applied. Because the appeals raised questions that went directly to the CRTC's statutory grant of power, the standard was correctness.

The majority found that applying a correctness standard, the Order was issued on the basis of an incorrect interpretation of the scope of authority under s. 9(1)(h). It noted that s. 9(1)(h) only authorizes the issuance of mandatory carriage orders - orders that require service providers to carry specific channels as part of their cable or satellite offerings - that include specified terms and conditions. Because the Order did not mandate that service providers distribute a channel that broadcasts the Super Bowl, but rather imposed a condition on those who already do, its issuance was not authorized by s. 9(1)(h) of the *Broadcasting Act.*

ALBERTA COURT OF APPEAL

AltaLink Management Ltd. v. Alberta Utilities Commission (2019 ABCA 482)

Public Utilities Act ss 101 & 102 - No Harm Test

In this decision, the Alberta Court of Appeal (“ABCA”) considered the AltaLink Management Ltd. (“AltaLink”) application for permission to appeal (“PTA”) AUC conditions on a transfer of ownership application. AltaLink had sought permission to transfer ownership in portions of a transmission line located on the Piikani Nation reserve and on the Blood Tribe reserve from AltaLink LP to limited partnerships. The limited partnerships would be owned 51 per cent by each of the Piikani Nation and by the Blood Tribe (PiikaniLink LP and KainaiLink LP). AltaLink LP would own the remaining 49 per cent of each limited partnership, would be the general partner of the new limited partnerships and would continue to operate the transmission line on the same basis as if it continued to be owned by AltaLink LP. The AUC approved the transfers, subject to conditions. AltaLink was successful in obtaining permission to appeal (“PTA”) some of those conditions.

Background

The facts which gave rise to the PTA applications involved a new 240kV transmission line from Pincher Creek to Lethbridge (“SW Line”). AltaLink’s preferred route crossed the Blood Tribe reserve and the Piikani Nation reserve and was significantly shorter than two alternative routes. The preferred route required the consent of the First Nations for the transmission line to cross their reserve, and the consent was provided in exchange for, among other things, the option to acquire an equity interest in the section of the SW Line located on their lands.

In 2009, the AUC approved the route that crossed the First Nations land, acknowledging that "each First Nation will have an opportunity to acquire an ownership interest in the new facilities constructed on their respective lands under a Limited Partnership (“LP”) structure".

The Piikani Nation and Blood Tribe exercised the options, and AltaLink applied for approval of transfers of portions of the SW Line to PiikaniLink LP and KainaiLink LP, pursuant to sections 101 and 102 of the *Public Utilities Act*. In considering those applications, the AUC applied its "no-harm" test.

The AUC determined that AltaLink's application violated the no-harm test because approval of the transfers would result in ongoing incremental annual costs to ratepayers for audit fees and hearing costs incurred by PiikaniLink LP and KainaiLink LP, as they would become transmission facility operators (“TFOs”). The costs were estimated at approximately $120,000 for 2017. The AUC concluded that this identified financial harm could be mitigated by excluding those costs from the tariffs, so that they would not be incurred by the ratepayers, but instead borne by the limited partnerships. As a result, the AUC approved the transfers on the condition that allowances for audit fees and hearing costs be removed from the revenue requirements of the proposed PiikaniLink LP and KainaiLink LP tariffs.

Court analysis and decision

The ABCA noted AltaLink’s submission that the AUC's "no-harm" test constituted an impermissible fettering of its discretion because the test precluded the AUC from considering all relevant factors, including its prior decision that routing the SW Line across the First Nations lands was in the public interest and the ongoing benefits from that routing. The AUC characterized its "no-harm" test as "specific to the transfers being proposed and . . . a forward looking exercise. What must be considered are the negative and positive effect of the proposed transfers themselves, and not what preceded them."

AltaLink and the First Nations further submitted that the AUC was bound to consider the entire course of dealings with the First Nations, and that it has a clear role in upholding the honour of the Crown in its dealings with First Nations.

The ABCA granted permission to appeal on the following questions of law, noting that consideration of specific factors would be determined by the panel hearing the appeal:

(a) Did the AUC improperly fetter its discretion when considering the transfers by applying the "no-harm" test?

(b) Did the AUC err by failing to consider all relevant factors?

ALBERTA ENERGY REGULATOR

Review of AER Industry Levy Methodology (Bulletin 2019-33)

AER Industry Levy

The AER is 100 per cent funded by industry, and is undertaking a review of how the administrative fee levied on energy development projects and activities is calculated. It will be soliciting stakeholder feedback to identify potential changes to the levy methodology and will be establishing a joint committee with industry stakeholders. The review will not affect the current administrative levy announced on November 29, 2019.

Requests for Regulatory Appeal by Werner Ambros and Sharon Ambros Encana Corporation (Requests for Regulatory Appeal Nos. 1919768 and 1924228)

Regulatory Appeal AER

In this decision, the AER considered the requests of Werner Ambros and Sharon Ambros (the "Ambroses") under section 38 of the *Responsible Energy Development Act* ("*REDA*") for regulatory appeals of the AER's decisions to approve three Encana Corporation ("Encana") applications for multi-well pads with sour gas wells; an application for a sour water pipeline and a sweet gas pipeline; and an application for a sour gas pipeline.

<u>Reasons for decision</u>

The AER found that the Ambroses may be directly and adversely affected by applications for two of the multi-well pads with sour gas wells and the sour gas pipeline because their residence and/or land is within the emergency planning zones for these approvals. The AER cited the Alberta Court of Appeal decision in *Kelly v. Alberta (Energy Resources Conservation Board)* 2009 ABCA 349 in support of this finding.

The AER held that it was required to hold a hearing pursuant to section 4 of the *Responsible Energy Development Act General Regulation,* which requires a hearing if the concerns of the eligible person requesting a regulatory appeal have not been addressed through an alternative dispute resolution process, or otherwise resolved between the parties.

ALBERTA UTILITIES COMMISSION

Amendments to AUC Rule 002, Rule 003 and Rule 032 (AUC Bulletin 2019-21)

AUC Rules

On November 22, 2019, the AUC approved amendments to Rule 002: Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors, Rule 003: Service Standards for Energy Service Providers and Rule 032: Specified Penalties for Contravention of AUC Rules, with an effective date of January 1, 2020.

The approved changes are summarized as follows:

- Rule 002 - Reporting requirements related to tariff billing removed from the rule and the template;
- Rules 002 and 003 - Complaint response reporting requirement removed from the rules and their respective templates; and
- Rule 032 - The 120-day rolling period previously used to determine the amount of the specified penalty, changed to a fixed, calendar-quarter period.

The AUC noted that there will be further consultation on Rules 002 and 032 in 2020.

Proposed Changes to AUC Rule 007 (AUC Bulletin 2019-19)

AUC Rules - Consultation

In June 2019, the AUC issued Bulletin 2019-10 which initiated a consultation process on potential changes to AUC Rule 007: Applications for Power of Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments.

Indigenous consultation was one of the topics identified in the bulletin. Based on feedback, the AUC decided to separate the development of Indigenous consultation processes and procedures from the Rule 007 review project to allow more time for discussion (Bulletin 2019-20).

The AUC received feedback on the first round of consultation. It proposed revisions to Rule 007 for seven of the issues (outlined from 1-7 below). It seeks further stakeholder feedback on these issues, and three additional issues numbered 8-10 below.

1) end-of-life management for power plants

2) emergency response plan

3) time extension applications for power plants

4) notification and participant involvement program

5) solar glint and glare assessment

6) shadow flicker

7) battery storage

8) maximum impact scenario

9) information requirement PP7

10) re-organization of Rule 007

Alberta Electric System Operator 2017 and 2018 Deferral Account Reconciliation (AUC Decision 24910-D01-2019)

Deferral Accounts, AESO

In this decision, the AUC approved the Alberta Electric System Operator ("AESO") request to settle its 2017 and 2018 net deferral account shortfall with market participants in the amount of $154.1 million, effective January 1, 2020.

<u>Background</u>

In September 2019, the AESO filed an application (the "Application") with the AUC requesting approval of its 2017 and 2018 deferral account reconciliation ("DAR") and changes to deferral account balances for 2016 through to 2006, representing the reconciled variances arising between the actual costs the AESO has incurred in providing system access service and the forecast amounts recovered in rates charged to market participants for those years. The AESO requested approval of the determination and allocation of a $154.1 million net deferral account shortfall and approval to collect and refund the allocated amounts.

<u>Application details</u>

The settlement of DAR balances only applied to customers who received system access under Rate Demand Transmission Service ("DTS") and Rate Fort Nelson Demand Transmission Service ("FTS") during 2018 through to 2006.

The Application reflected the AESO's first reconciliation of deferral account balances for 2017 and 2018. The AESO DARs for production years

2017 and 2018 were prepared on a retrospective, annual and production year basis and relied on the final approval granted by the AUC in Decision 22942-D02-2019, to apply the revised DAR methodology for 2017 and future production years.

The Application also reflected the AESO's subsequent reconciliations for the years 2016 through to 2006 deferral account balances. The DARs for years 2016 through to 2006 were prepared on a retrospective, monthly and production month basis, consistent with the methodology used in all reconciliations from 2016 to 2004.

AUC findings

The AUC directed the AESO to either file future DAR applications by quarter two of a calendar year and/or to provide distribution facility owners ("DFOs") with estimates of the annual deferral account shortfall or surplus amounts by the end of quarter one. This allows DFOs to be in a better position to collect or refund these amounts in their transmission access charge deferral account applications during the same calendar year the AESO seeks settlement of these amounts.

The AUC reviewed the AESO's methodology and found it consistent with the methodology approved for DAR applications in Decision 22942-D02-2019. The AUC reviewed the allocation of the deferral account balances and found that it was consistent with previous DAR applications approved by the AUC and the 2018 ISO tariff. The AUC also reviewed the AESO's proposed settlement process and found that it was reasonable and consistent with previous DAR applications approved by the AUC.

The AUC approved the deferral account balances and the net deferral account shortfall in the amount of $154.1 million.

AltaGas Utilities Inc. 2020 Annual Performance-Based Regulation Rate Adjustment (AUC Decision 24883-D01-2019)

Performance-Based Regulation

In this decision, the AUC considered the 2020 annual performance-based regulation ("PBR") rate adjustment filing of AltaGas Utilities Inc. ("AltaGas"). The decision included the following determinations by the AUC:

- the adjustments to the interim notional 2017 revenue requirement and 2018 base K-bar for the 2018-2022 PBR plans for AltaGas were approved but remained interim since certain placeholders remained unresolved;
- the 2020 distribution service rates, special charges, Rider F and the corresponding rate schedules were approved effective January 1, 2020, on an interim basis;
- the customer and retailer terms and conditions of gas distribution service were approved effective January 1, 2020; and
- the rates that were approved for 2017 on an interim basis were approved on a final basis.

Background

In September 2019, AltaGas submitted its 2020 annual PBR rate adjustment filing to the AUC, requesting approval of its 2020 distribution service rates, special charges, Rider F and corresponding rate schedules, to be effective January 1, 2020, on an interim basis. AltaGas also requested approval of its customer and retailer terms and conditions ("T&Cs") of gas distribution service, to be effective January 1, 2020.

Ongoing proceedings with the potential to impact AltaGas 2018, 2019, and 2020 PBR rates

AltaGas advised the AUC that placeholders will remain until decisions are issued in AUC Proceedings 24161, 24325, 24609 and 25031.

Adjustments to the interim notional 2017 revenue requirement and 2018 base K-bar

AltaGas was directed to review all of its calculations and adjust for any material impacts regarding the leap year in a future application. The 2018 K-bar reduction of $51,949 and refund to customers of $2,700 in associated carrying costs were approved. The AUC noted that the 2018 K-bar amount remains interim pending the outcomes of the proceedings outlined above.

I factor and the resulting I-X index

The AUC approved the I factor of 1.36 per cent and the resulting I-X index value of 1.06 per cent for 2020.

K factor

AltaGas currently has one Type 1 capital placeholder, approved in Decision 23898-D01-2019 (Errata). The AUC approved AltaGas' placeholder request for cost recovery of 90 per cent of the management-approved internal 2019 forecast of $10.0 million in total forecast project cost associated with the Etzikom lateral project and the 2019 revenue requirement associated with this placeholder of $0.17 million.

The AUC reviewed the detailed calculation of the revenue requirement associated with AltaGas' 2020 Etzikom lateral project and found that the calculations were correct. The $0.68 million 2020 Etzikom lateral revenue requirement was approved, subject to the AUC's ultimate determinations, in the true-up application that AltaGas indicated would be filed in 2020, as to whether this project meets the Type 1 capital criteria and whether the expenditures are prudent.

K-bar factor

The AUC approved AltaGas' 2020 K-bar in the amount of $6.95 million. It noted that this amount remains interim, pending the outcomes from the proceedings detailed above. It further noted that the 2020 K-bar will be subject to a further true-up for the 2020 actual approved cost of debt.

Y and Z factors

Y and Z factor materiality threshold

The AUC found that AltaGas calculated its Y and Z factor materiality threshold of $0.53 million for 2020 using the methodology prescribed in Decision 20414-D01-2016 (Errata) and approved this amount on an interim basis. The AUC further noted that pursuant to Decision 20414-D01-2016 (Errata), this interim threshold amount will be finalized upon approval of the final notional 2017 revenue requirement.

Y factor

AltaGas applied for Y factor adjustments for 2020 that included AUC assessment fees; Utilities Consumer Advocate assessment fees; hearing costs for interveners; Natural Gas Settlement System Code; production abandonment costs; and carrying charges on true-up balances. AltaGas' Y factor amounts were approved, as filed.

Forecast billing determinants and Q

Based on its review and assessment of AltaGas' methodology and billing determinants in this proceeding, the AUC found that the methodology and the resulting 2020 forecast billing determinants were reasonable. The AUC reviewed AltaGas' proposed changes to its forecasting methodology for the irrigation rate class and found the changes reasonable and reasonably likely to result in improved long-term forecasting accuracy.

The AUC approved AltaGas' proposed change to its forecasting methodology for the irrigation rate class and directed AltaGas to continue using this forecasting methodology for the remainder of the PBR term unless otherwise directed by the AUC. The 2020 forecast billing determinants were approved as filed.

The AUC also reviewed AltaGas' calculation of its 2020 Q and found it to be reasonable. The AUC therefore approved AltaGas' 2020 Q of 0.04 percent.

Distribution rates

The AUC approved AltaGas' 2020 distribution rates and special charges on an interim basis, effective January 1, 2020. These 2020 rates shall remain interim until remaining placeholders have been approved by the AUC. The 2020 rates will be finalized following such approvals and any required true-up adjustments will be made in accordance with directions subsequently provided by the AUC.

The AUC found that all outstanding K factor and Y factor true-ups and placeholder adjustments had been resolved for 2017 and approved AltaGas' 2017 rates as final.

AltaGas Utilities Inc. 2018 Depreciation Study (AUC Decision 24161-D03-2019)

Depreciation Study

In this decision, the AUC provided its findings on the AltaGas Utilities Inc. ("AltaGas") 2018 depreciation application, which was supported by a depreciation study. The AUC approved the service lives, Iowa life-curves ("life-curves") and estimated net salvage percentages and resulting changes in depreciation parameters as proposed by AltaGas for its depreciation study accounts.

With regard to the items summarized below, the AUC denied AltaGas' proposed depreciation changes for the following reasons:

- the AUC rejected AltaGas' proposal to change the net salvage rate from negative ten per cent to negative 30 per cent for Account 465 Transmission Mains and directed AltaGas, in its compliance filing, to incorporate a negative 15 per cent net salvage rate instead;

- the AUC denied AltaGas' proposal to change the net salvage rate from negative 35 per cent to negative 75 per cent for Account 467 Transmission Measuring and Regulation Station Equipment and directed AltaGas, in its compliance filing, to incorporate the currently approved negative 35 per cent net salvage rate for this account;

- the AUC rejected AltaGas' proposal to change the net salvage rate from negative 30 per cent to negative 100 per cent for Account 473 Distribution Services and directed AltaGas, in its compliance filing, to increase the net salvage rate for this account to negative 50 per cent; and

- the AUC denied AltaGas' proposal to change the net salvage rate for Account 475 Distribution Mains from negative 10 per cent to negative 75 per cent and directed AltaGas, in its compliance filing, to incorporate a negative 25 per cent net salvage rate for this account.

<u>Background</u>

In December 2018, AltaGas filed an application with the AUC requesting approval of its 2018 depreciation study. Specifically, AltaGas requested approval of:

- the service life depreciation rates and net salvage rates proposed in the application for the 2018-2022 PBR term, as recommended by AltaGas' external consultant, Concentric Advisors ULC ("Concentric") in AltaGas' 2018 depreciation study; and

- collection, on an interim basis, of a 50 per cent placeholder of the forecast 2018 and 2019 depreciation expense aggregate shortfall by implementation of a Rate Rider F, effective March 1, 2019, until December 31, 2019 (the "Rider F request").

<u>Rider F request</u>

For the reasons detailed in Decision 24161-D01-2019, the AUC approved a Rider F that recovers 25 per cent of AltaGas' applied-for 2018 and 2019 depreciation expense shortfall, on a placeholder basis, effective August 1, 2019, to December 31, 2019, as well as a subsequent Rider F placeholder for 2020, to be implemented effective January 1, 2020, to December 31, 2020.

<u>AUC-initiated review and variance</u>

Proceeding 24609 is a review and variance proceeding to consider the method of accounting for new depreciation parameters and expense in rates under the 2018-2022 PBR term. The AUC noted that all adjustments to going-in rates and base K-bar, and subsequent annual adjustments resulting from changes to depreciation parameters approved are interim pending the conclusion of Proceeding 24609.

<u>AltaGas' depreciation study</u>

AltaGas' current depreciation parameters and related depreciation expense were approved in 2012 based on a depreciation study completed in 2010. A 2018 depreciation study was prepared by Concentric for AltaGas, and was based on AltaGas' natural gas transmission, distribution, and general plant accounts as at December 31, 2017.

The proposed depreciation parameters would result in an overall increase of approximately $7.9 million and $8.6 million in depreciation expense for 2018 and 2019, respectively, compared to the depreciation expense that would be recorded for these two years using the depreciation parameters approved in Decision 2012-091. Approximately 90 per cent of the requested increase in depreciation expense was due to increased net salvage (negative), with the remainder due to changes in asset service lives.

<u>Service life and /or life-curve adjustments</u>

Account 474.01 Customer AMR

Account 474.01 Customer AMR is a subaccount to Account 478 Meters. Total investment in the account was $16.352 million at 2018 year end, approximately 2.7 per cent of AltaGas' total asset investment.

AltaGas proposed to retain the use of amortization accounting and a 15-SQ life parameter for this account.

The AUC found that extending the average service life would not benefit the utility or rate payers. Accordingly, the AUC approved the continued use of the 15-year estimated average service life.

AltaGas was directed, in the next depreciation study, to provide a table of the number of remaining meters with encoder receiver transmitter modules installed in order for the AUC to evaluate the continued need for the account.

Account 475 Distribution Mains

AltaGas requested a change from the previously approved life parameter of a 62-R2 life-curve to a 65-R2 life-curve. The AUC approved AltaGas' request to change the previously approved life parameter of a 62-R2 life-curve to a 65-R2 life-curve. However, the AUC directed AltaGas to re-examine this parameter at the time of its next depreciation study and to advise the AUC if further changes are justified based on the makeup of the account at that time.

Net salvage

During the proceeding, several issues arose with respect to net salvage and the costs that are charged to cost of retirement, including general issues regarding moderation and gradualism principles, site remediation, five per cent allocation to cost of removal and alternative accounting approaches. The other four issues were account-specific (Account 465 Transmission Mains; Account 467 Transmission Measuring and Regulation Station Equipment; Account 473 Distribution Services; and Account 475 Distribution Mains).

Moderation and gradualism principles

The AUC agreed that the depreciation principles of gradualism and moderation are important and should be included in the assessment of a depreciation study, especially in situations where a large change in a depreciation parameter or parameters has been proposed. This was further addressed in later parts of the decision that dealt with the four specific net salvage accounts.

Site remediation

The AUC shared concerns raised by the Utilities Consumer Advocate ("UCA") that AltaGas' current practice of recording site remediation and site clean up costs to cost of removal instead of operating costs where no assets are retired, limits the level of visibility into and regulatory review of such expenditures. This is of particular concern where the dollar amounts charged to cost of removal are large relative to the original amounts of the assets being retired. Having regard to the above concerns and the failure of AltaGas to provide sufficient justification for continuation of its practice, the AUC considered that this practice should be adjusted.

The AUC directed AltaGas, for 2018, 2019 and future years, to charge site remediation costs to operating costs and not to cost of removal where there are no related asset retirements occurring concurrently or within a reasonably foreseeable period of time (such as in the same fiscal year) and the existing assets continue to be used. Site remediation costs caused by assets that are either in the process of being retired or have been retired can still be charged to cost of removal. AltaGas was further directed to reflect this change for all accounts that include site remediation costs as part of net salvage, in its compliance filing to this decision.

Five per cent allocation to cost of removal

The AUC accepted evidence that AltaGas has not used the five per cent allocation method on mains projects (Account 465 Gas Transmission – Mains replacement). However, the AUC noted that the method for allocating costs of removal with respect to AltaGas' remaining accounts was not clear from the data presented and was not clearly explained by AltaGas.

The AUC directed AltaGas, in the compliance filing, to provide the amounts charged to cost of removal by allocation (and not actual costs) in each account, and the method of allocation used for the years 2016 through 2018.

Alternative accounting approaches

AltaGas requested net salvage rates of negative 75 per cent for accounts 467 and 475, and a net salvage rate of negative 100 per cent for Account 473.

The UCA recommended that where net salvage rates are more negative than negative 50 per cent, AltaGas be directed to review, report on and adopt alternatives to the traditional approach for net salvage. UCA's experts considered any negative net salvage rates more negative than negative 60 per cent to be atypical.

The AUC agreed that an examination of alternatives to the traditional method of net salvage may be of benefit where there is a large gap between AltaGas' net salvage rates and those of its peer comparators or where the traditional approach to net salvage may result in atypical outcomes. However, the AUC considered that such an examination could be time consuming and is better undertaken in connection with a full depreciation study. The AUC therefore directed AltaGas in its next depreciation study to review and report on alternatives to the traditional approach to net salvage for any account for which AltaGas has proposed net salvage rates that are more negative than negative 60 per cent, or for which the mean net salvage percentage for the peer utility comparator group for AltaGas is more than 25 per cent different from the net salvage rate proposed by AltaGas. For all alternatives considered, AltaGas should explain in detail why the alternative was either adopted or rejected.

Account 465 Transmission Mains

AltaGas requested a change in the net salvage rate for Account 465 Transmission Mains from negative 10 per cent to negative 30 per cent.

The AUC found that AltaGas failed to offer sufficient justification to change the net salvage rate for this account from negative 10 per cent to negative 30 per cent. AltaGas was directed to incorporate a negative 15 per cent net salvage rate for this account in its compliance filing to this decision.

Account 467 Transmission Measuring and Regulation Station Equipment

AltaGas proposed to change the net salvage rate for Account 467 Transmission Measuring and Regulation Station Equipment from negative 35 per cent to negative 75 per cent.

AltaGas' request was denied and AltaGas was directed, in its compliance filing to this decision, to incorporate the currently approved negative 35 per cent net salvage rate for this account.

Account 473 Distribution Services

AltaGas proposed to change the net salvage rate for Account 473 Distribution Services from negative 30 per cent to negative 100 per cent.

The AUC found that a net salvage rate of negative 50 per cent was reasonable. AltaGas was directed to set the net salvage rate for this account at negative 50 per cent and to incorporate a negative 50 per cent net salvage rate for this account in its compliance filing to this decision.

Account 475 Distribution Mains

AltaGas proposed to increase its net salvage rate for Account 475 Distribution Mains from negative 10 per cent to negative 75 per cent.

The AUC found that a net salvage rate of negative 25 per cent took into account the upward trend in net salvage activity as well as gradualism and moderation. It was also within the range of the peer comparison of Canadian utilities.

ATCO Electric Ltd. Transmission Decision on Preliminary Question Application for Review of Decision 22393-D02-2019 Hanna Regional Transmission Development Deferral Account (AUC Decision 24754-D01-2019)

Review and Variance, Legal Costs

In this decision, an AUC review panel considered whether to grant an application (the "Application") filed by ATCO Electric Ltd. ("ATCO") requesting a review and variance ("R & V") of specific findings in AUC Decision 22393-D02-2019 (the "Decision"). The Decision addressed an application from ATCO requesting approval of 18 transmission capital projects that collectively comprise the Hanna Region Transmission Development ("HRTD") program, which was considered in Proceeding 22393. The review application requested reconsideration of the AUC's determination to reduce ATCO's legal costs related to the HRTD program.

The review panel denied the review Application.

<u>Background</u>

In the Decision, the hearing panel held that ATCO had failed to meet its burden to establish that certain of the legal costs invoiced by Bennett Jones LLP to

ATCO and charged to the HRTD program were just and reasonable.

The hearing panel made a number of findings which were the subject of the R & V application. It noted that ATCO chose to outsource legal services rather than use internal legal resources. It also appeared to the hearing panel that ATCO used external legal counsel to perform tasks that could and should have been performed by a project manager. The hearing panel also noted instances of external counsel giving advice on issues that should have been managed by ATCO human resources personnel.

Further, the hearing panel found that legal fees charged at the partner level by Bennet Jones in relation to the HRTD program exceeded peer rates by approximately 10 per cent. Given ATCO's admitted long-standing relationship with Bennett Jones and the volume of work that ATCO directed to Bennett Jones, the hearing panel expected that ATCO demand and receive an overall percentage reduction to all of its fees during the entire period during which work was being performed on this project.

Ultimately, the hearing panel directed ATCO to remove certain charges and decrease overall invoices.

<u>The AUC review process and ATCO grounds for review</u>

The AUC review panel briefly outlined the basis of its authority to review AUC decisions as set out in section 10 of the *Alberta Utilities Commission Act,* and noted that AUC Rule 016 sets out the process for considering an application for review.

ATCO's grounds for review under Rule 016 were set out, and the review panel examined each of these grounds in turn.

<u>Review Panel findings</u>

Procedural fairness

The review panel found that ATCO was provided with reasonable notice of the concerns regarding the legal costs that ATCO sought to have charged to the HRTD program. Through the process, ATCO was also given a reasonable opportunity to address the prudence of those legal costs and to respond to the evidence and argument of the other party to the proceeding with respect to those costs. The review panel found no error of fact, law or jurisdiction, and denied the request for a review on this ground.

Previously unavailable facts

The review panel noted that under the section of Rule 016 that deals with previously unavailable facts, the applicant must satisfy the review panel of the existence of previously unavailable facts material to the decision that existed prior to the issuance of the decision, but that could not have been discovered at the time by exercising reasonable diligence.

The review panel found that ATCO's assertion that the concerns raised by the AUC and the Consumers' Coalition of Alberta ("CCA") in the original proceeding did not relate to specific legal entries and was not supported by the record of that proceeding.The request for review on this ground was denied.

Changed circumstances

The review panel was not persuaded that there was an "increased standard of proof" or that the AUC's concerns were not known to ATCO. The review panel further noted that the fact that ATCO was unsuccessful meeting its onus to demonstrate the prudence of certain legal costs related to the HRTD program is not a changed circumstance material to the Decision warranting review. ATCO's request for a review on this ground was therefore denied.

The 10 per cent reduction to associate level fees

The review panel found ATCO failed to demonstrate that the hearing panel disregarded ATCO's evidence or arguments related to the 10 per cent reduction to fees. The hearing panel was aware of ATCO's evidence and arguments. It weighed the evidence, considered the arguments and ultimately reached a decision directing the general 10 per cent reduction as a result of the long-standing relationship between the two parties, and the volume of work being conducted. That ATCO was dissatisfied with the weight accorded to the evidence by the hearing panel and with the outcome more generally was not grounds for review.

<u>AUC findings</u>

The Application was dismissed.

ATCO Electric Ltd. 2020 Transmission Facility Owner Tariff (AUC Decision 25005-D01-2019)

Transmission Facility Owner Tariff

In this decision, the AUC found that the ATCO Electric Ltd ("ATCO") approved 2020 interim tariff should be set based on the 2019 currently applied-for rates in Proceeding 248051 in the amount of $691.9 million effective January 1, 2020, until otherwise directed by the AUC.

Background and application

ATCO filed an application with the AUC, requesting interim approval of its forecast 2020 Transmission Facility Owner ("TFO") tariff, effective January 1, 2020. ATCO requested approval of the interim tariff based on its forecast 2020 tariff of $719.7 million, resulting in an interim tariff of $59.98 million on a monthly basis. ATCO submitted that the applied-for interim tariff was higher than the approved 2019 interim tariff primarily due to an increase in the recovery of depreciation associated with net salvage and life parameter updates, and inflationary pressures on operating costs.

AUC findings

The AUC acknowledged ATCO's arguments as to the probability of its forecasted revenue shortfall and why it considered that its requested increase should not be subject to any reduction. However, ATCO's requested revenue requirements, including the matters identified as the reason for the requested increase, had not yet been adjudicated and so remained uncertain.

The AUC noted that a significant portion of the requested interim tariff increase was related to contentious items, as $30.7 million of the requested $45.9 million interim tariff increase was from recovery of depreciation.

The AUC found that the approved interim tariff should be set based on ATCO's 2019 currently applied for tariff of $691.9 million. The AUC considered this to be a reasonable point of reference, as the 2019 currently applied-for tariff was based on a rate structure and costing methodology which were thoroughly tested in ATCO's 2018-2019 general tariff application. Further, the AUC considered that an interim tariff of $691.9 million would help smooth out the total increase in costs for 2020 and avoid rate shocks to ratepayers.

ATCO Gas and Pipelines Ltd. 2017 Capital Tracker True-Up Compliance Filing to Decision 23789-D01-2019 (AUC Decision 24333-D01-2019)

Capital Tracker

This decision sets out the AUC determination regarding the compliance of ATCO Gas, the distribution division of ATCO Gas and Pipelines Ltd., with the AUC's directions issued in Decision 23789-D01-2019.

The AUC found that ATCO Gas did not comply fully with the AUC's directions and denied, in part, ATCO Gas' 2017 applied-for K factor adjustments.

The AUC approved:

(a) the 2017 actual K factor for the New Regulating Meter Station ("NRMS") Program in the amount of $0.521 million for ATCO Gas North and $0.366 million for ATCO Gas South; and

(b) that portion of the 2017 actual cost (i.e., net book value or "NBV") of assets transferred from ATCO Pipelines, the transmission division of ATCO Gas and Pipelines Ltd., to ATCO Gas in excess of forecast attributable to contributions being transferred and recorded separately as opposed to being netted against capital expenditures as they were in the forecast.

The AUC denied:

(a) the portion of the 2017 actual cost (i.e., NBV) of assets transferred from ATCO Pipelines to ATCO Gas in excess of forecast attributable to:

  (i) additional assets required as a result of the completion of the detailed design; and

  (ii) additional capital work completed on the transmission line after the original estimate.

The AUC directed ATCO Gas to calculate and remove the capital additions associated with these costs from its calculation of its 2017 K factor.

Compliance with AUC directions

Direction 1 - Breakdown of costs for NRMS program projects

Direction 1 required ATCO Gas to provide a breakdown of costs for the NRMS program projects identified by the AUC, which reflected the top five projects in terms of capital expenditures for each of ATCO Gas North and ATCO Gas South.

The AUC found that ATCO Gas complied with Direction 1. The 2017 actual K factor for the NRMS Program in the amount of $0.521 million for ATCO Gas North and $0.366 million for ATCO Gas South was approved.

Direction 2 - Explanation of increases in net book value for assets transferred from ATCO Pipelines to ATCO Gas

Direction 2 in Decision 23789-D01-2019 required a further explanation of material increases in NBV of transferred Utility Pipelines Replacement ("UPR") assets:

> ... ATCO Gas is directed to provide a list in the compliance filing to this proceeding that includes each UPR pipeline project, a detailed description and associated dollar amounts of the additional assets required as of the time of the transfer of assets. The additional assets that must be included in the list are those assets required to complete the detailed design and those assets that were required due to the additional capital work completed on the transmission line two years or more after the original NBV estimate was generated.

The AUC found that ATCO Gas did not meet its evidentiary burden of adequately explaining and reasonably justifying the increase in NBV due to (i) work orders dating back to the 1950s relating to additional assets required as a result of the completion of the detailed design; and (ii) additional capital work completed on the transmission line after the original estimate.

Accordingly, the AUC found that the information provided by ATCO Gas did not reasonably support a finding that the increased costs (i.e., NBV) arising from the claimed need for additional assets or additional capital work beyond the costs originally anticipated were prudent.

The AUC accepted ATCO Gas' explanation for the increase in NBV for (i) contributions being transferred and recorded separately as opposed to being netted against capital expenditures (as they were in the forecast) and approved these amounts for inclusion in the K factor. The AUC was not persuaded that the evidence filed by ATCO Gas adequately established that the costs associated with the (ii) additional assets required as a result of the completion of the detailed design, and the (iii) additional capital work completed on the transmission line after the original estimate were prudent and, as such, required these amounts to be removed from ATCO Gas' 2017 K factor.

The AUC provided the following directions to ATCO for its 2021 annual rate adjustment application:

(a) to review all the UPR assets transferred from ATCO Pipelines to ATCO Gas to confirm that all of the assets are used and useful or required to be used for gas distribution service. ATCO Gas must identify in its 2021 PBR annual rate filing any assets that are not required for the provision of gas distribution service and remove those assets from the ATCO Gas rate base;

(b) to revise its accounting test for 2017, based on the findings and directions in this decision, and to reassess whether the capital tracker programs or projects included in the 2017 true-up satisfy the accounting test requirements of Criterion 1; and

(c) to reassess whether its projects or programs included in the 2017 true-up continue to satisfy the two-tiered materiality test requirement of Criterion 3.

ATCO Gas and Pipelines Ltd. 2020 Annual Performance-Based Regulation Rate Adjustment (AUC Decision 24880-D01-2019)

Performance-Based Regulation

In this decision, the AUC considered ATCO Gas and Pipelines' 2020 annual performance-based regulation ("PBR") rate adjustment filing. The AUC made the following determinations:

- the adjustments to the interim notional 2017 revenue requirement and 2018 base K-bar for the 2018-2022 PBR plans for ATCO Gas were approved. However, these amounts were to remain interim since certain placeholders remained unresolved;

- the 2020 distribution rate schedules were approved effective January 1, 2020, on an interim basis; and

- the customer and retailer terms and conditions for gas distribution service were approved effective January 1, 2020.

Background and Application

On September 10, 2019, ATCO Gas submitted its 2020 annual PBR rate adjustment filing to the AUC, requesting approval of its ATCO Gas North and ATCO Gas South rate schedules, as set out in its application, to be effective January 1, 2020, on an interim basis. ATCO Gas also requested approval of its customer and retailer terms and conditions ("T&Cs") for gas distribution service, to be effective January 1, 2020.

Adjustments to the interim notional 2017 revenue requirement and 2018 base K-bar

The AUC reviewed ATCO Gas' schedules showing the PBR formula calculations of 2020 rates and was satisfied that ATCO Gas incorporated the adjustments in the calculations of 2020 rates. However, the AUC noted that the adjustments continue to remain interim pending the finalization of all outstanding placeholders such as the AUC determinations arising from Proceedings 24609, 24188 and 24325, and other future proceedings that address the IT common matters-related adjustments and any related compliance filing(s).

The AUC also noted that it continues to be of the view that further adjustments to 2018 going-in rates should generally take place after all of the remaining placeholders have been finalized.

I factor and the resulting I-X index

The AUC reviewed ATCO Gas' calculations of the 2020 I factor and found them to be consistent with the methodology set out in Decision 2012-237 and confirmed in Decision 20414-D01-2016 (Errata).

K-bar factor

The AUC approved ATCO Gas' 2020 K-bar in the amount of $30.6 million. This amount was to remain interim pending finalization of the IT common matters placeholder, all actual capital tracker amounts incurred during the 2013-2017 PBR term and any related compliance filing(s) and updated depreciation parameters. The 2020 K-bar would be subject to a further true-up for the 2020 actual approved cost of debt.

Y and Z factor materiality threshold

The AUC approved ATCO Gas' Y and Z factor materiality threshold to be $2.059 million for ATCO Gas North, and $1.722 million for ATCO Gas South on an interim basis. As set out in Decision 20414-D01-2016 (Errata), this interim threshold amount would be finalized upon approval of the final notional 2017 revenue requirement.

Y factor

The AUC approved a 2018 efficiency carryover mechanism ("ECM") true-up amount of a refund of $4,000, and a 2019 ECM true-up refund of $4,000. These ECM amounts will be finalized by ATCO Gas following the determination of the final notional 2017 mid-year rate base.

Regarding the remainder of the Y factor amounts applied for, the AUC determined that all of these costs were of a type that the AUC approved as Y factor treatment in Decision 20414-D01-2016 (Errata).

The Y factors were approved.

Carrying charges

The AUC reviewed the calculation of the ATCO Gas North and ATCO Gas South carrying charges and found them properly calculated and consistent with the applicable provisions of Rule 023 and Decision 2012-237.

Forecast billing determinants and Q

Based on its review and assessment of ATCO Gas' methodology and billing determinants in this proceeding, the AUC found that the methodology and the resulting 2020 forecast billing determinants were reasonable. The 2020 forecast billing determinants were approved as filed.

The AUC also reviewed ATCO Gas' calculation of its 2020 Q and found it to be reasonable. The AUC therefore approved ATCO Gas' 2020 Q of 1.40 per cent and 1.35 per cent for the North and South, respectively.

The AUC directed ATCO Gas to provide Q value calculations in its future annual PBR filings.

Distribution rates

The AUC reviewed the schedules setting out the 2020 PBR rate calculations and observed that ATCO Gas calculated its 2020 rates consistent with its practices and methodologies used during the 2013-2017 PBR term and previously accepted by the AUC. The AUC accepted the general principles and methodologies utilized by ATCO Gas for calculating its 2020 PBR rates.

The AUC also reviewed the typical bill impacts in assessing the likelihood of rate shock resulting from the proposed 2020 PBR rates. The AUC observed that the month-over-month increases to customer bills were not expected to exceed 10 per cent for all rate classes.

The rates were approved on an interim basis. The AUC noted that the 2020 rates would remain interim until the remaining placeholders and the issue of anomalies in relation to the utility's going-in rates have been addressed by the AUC.

ATCO Pipelines 2020 Interim Revenue Requirement Application (AUC Decision 25061-D01-2019)

Interim Revenue Requirement

In this decision, the AUC approved a 2020 interim revenue requirement in the amount of $289,503,750 (after the removal of forecast franchise taxes) to be collected by ATCO Pipelines by way of a monthly rate of $24,125,313 from NOVA Gas Transmission Ltd., effective January 1, 2020.

Background

On August 15, 2019, ATCO Pipelines filed with the AUC its 2019-2020 general rate application ("GRA") compliance filing, seeking approval of its 2019-2020 final revenue requirements in the amount of $274,751,000 and $304,698,000, respectively. ATCO Pipelines noted that its 2020 interim revenue requirement was based on 100 per cent of its applied-for 2020 revenue requirement per its 2019-2020 GRA compliance filing, and a decision on this compliance filing proceeding was not expected to be issued by the AUC before January 1, 2020.

AUC findings

The AUC approved a 2020 interim revenue requirement increase of $11,837,750, which represented 75 per cent of the original applied-for increase, less the potential excess collection of $6,070,000 in ATCO Pipelines' 2019 interim revenue requirement approval.

The AUC found that ATCO Pipelines' request to collect 100 per cent of its applied-for 2020 revenue requirement per its 2019-2020 GRA compliance filing was not reasonable, because in addition to the 2019 excess interim revenue requirement collection, there was uncertainty related to certain costs within ATCO Pipelines' 2019-2020 GRA compliance filing.

The AUC was persuaded that the quantum need and public interest considerations weighed in favour of approving a reduced interim revenue requirement adjustment. The AUC determined that a reasonable interim 2020 revenue requirement for ATCO Pipelines is $289,503,750 or $292,658,750 before the removal of forecast franchise taxes. This represents a total increase of $11,837,750 over ATCO Pipelines' approved 2019 revenue requirement.

Canadian Utilities Limited - Application for Transfer of Ownership Interest in ASHCOR Technologies Ltd (AUC Decision 25118-D01-2019)

Public Utilities Act Section 101, Gas Utilities Act Section 26, No-harm Test

In this decision, the AUC considered whether to approve Canadian Utilities Limited's ("CUL") request to transfer its indirect ownership interest in ASHCOR Technologies Ltd. ("ASHCOR") to ATCO Ltd. ("ATCO"). The AUC approved CUL's application.

Background

CUL controls CU Inc., which in turn owns 100 per cent of ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. (the "ATCO Utilities"). Pursuant to the *Designation Regulations*, CUL is a designated owner of a public utility for the purposes of sections 101, 102 and 109 of the *Public Utilities Act* and a designated owner of a gas utility for the purposes of sections 26 and 27 of the *Gas Utilities Act*.

CUL provided details of the transaction in which CUL would sell its indirect ownership interest in ASHCOR (an independent marketer of fly ash and other combustion by-products) to ATCO (the “ASHCOR Share Transaction”).

CUL submitted that the ASHCOR Share Transaction would not adversely affect any member of the public of Alberta who is currently receiving utility service or who will receive utility service from the regulated ATCO Utilities.

AUC findings

The AUC found the ASHCOR Share Transaction outside of the ordinary course of business for CUL, and accordingly noted that it had to be approved by the AUC. It applied the no-harm test and found that the transaction would not have potentially harmful operational effects on regulated customers that may impair the integrity and reliability of the two systems operated by the ATCO Utilities. The AUC also found that approval of the application would not result in any financial harm to customers.

The AUC found that the requirements of the no-harm test were satisfied and approved the ASHCOR Share Transaction.

City of Calgary Decision on Preliminary Question - Application for Review of Decision 20514-D02-2019 and Commission Rulings on Eligibility for Costs Recovery (Decision 24760-D01-2019)

Review and Variance, Costs Rulings

In this decision, an AUC review panel considered whether to grant a review application filed by the City of Calgary (“Calgary”) on costs rulings (the “Costs Rulings”) made in the *ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. Information Technology Common Matters Proceeding* (the “IT Common Matters Proceeding”). The AUC review panel denied the review application.

Background

Canadian Utilities Limited controls CU Inc., which in turn owns 100 per cent of ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. (the “ATCO Utilities”).

An AUC hearing panel had ruled that Calgary, as a municipality, was ineligible to claim recovery of costs incurred with its intervention in AUC rate proceedings. The hearing panel made reference to the long-standing rationale for the exclusion of municipalities from the cost recovery mechanism, noting that the AUC’s cost recovery rule states that the AUC may award costs to an intervener representing persons with a “substantial interest in the subject matter” of a proceeding, but which “does not have the means to raise sufficient financial resources to enable [it] to present its interests adequately.”

Calgary submitted that previously unavailable facts could lead the AUC to materially vary or rescind the Costs Rulings. These previously unavailable facts included significant delays in the IT Common Matters Proceeding, limited transparency and disclosure of information, an expanded scope in that proceeding, the need for repeated motions, and the extent of the confidential material on the record.

Calgary also submitted that the Costs Rulings contained errors in fact or mixed fact and law that could lead the AUC to materially vary or rescind the Costs Rulings. These errors of fact or mixed fact and law related to the hearing panel’s consideration of: the scope of the proceeding, the implications of not granting costs recovery eligibility with regard to the conduct of the ATCO Utilities and its shareholders, the “free-rider” effect and the benefits of confidential treatment of information.

The review panel rejected Calgary’s arguments regarding previously unavailable facts. It noted that Rule 022 does not set out criteria for cost eligibility based on the anticipated duration or complexity of a proceeding, or if the costs of participation exceed what was initially anticipated. It emphasized that the exercise of discretion with respect to costs should not be interfered with lightly. The review panel also noted that the hearing panel would have been fully aware of the ATCO Utilities lengthy and contentious history of IT master service agreement related proceedings when it made its Costs Rulings.

The review panel also rejected arguments regarding errors in fact or mixed fact and law. It found no errors in the proceeding scope and noted that Rule 022 does not contemplate costs recovery eligibility as a means to manage conduct between parties. It noted that the “free-rider” issue was directly considered by the hearing panel, and found no errors were made by the hearing panel by not expressly considering the existence of confidential material in making its determination.

The application for review was dismissed.

Direct Energy Regulated Services 2019 Default Rate Tariff and Regulated Rate Tariff (AUC Decision 24237-D01-2019)

Default Rate Tariff - Regulated Rate Tariff - Revenue Requirement

Direct Energy Regulated Services ("DERS") applied for approval of its 2019 default rate tariff ("DRT") and regulated rate tariff ("RRT") revenue requirements and rates. The AUC generally approved the application, requiring certain changes.

DERS is a business unit of Direct Energy Marketing Limited ("DEML") and performs the natural gas DRT and electricity RRT functions in the service territories of ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd., respectively.

Customer care and billing and customer information system

The AUC found that the 2019 fair market value ("FMV") estimates of $3.7247 per site per month for customer care and billing services ("CC&B") services and of $1.14 per site per month for the customer information system ("CIS") were reasonable.

Merchant fees costs

The AUC found that DERS methodology to forecast the number of customers who pay their bills by credit card, the total amount of the bills paid by credit card, and the fees charged by the credit card companies, more accurately reflected merchant fee costs, compared to alternate methodologies considered. In addition, the AUC approved a multiplier of 1.1598 to be used in DERS' forecast for its 2019 merchant fees.

Working capital costs

The AUC directed corrections for the DRT and RRT schedules. In addition, the AUC noted revisions would be required in the working capital schedule, to account for findings and directions related to customer operations costs, merchant fees costs, corporate services costs, and other administration costs. The change in these costs would also change the 2019 overall revenue requirements for the DRT and the RRT, which would require the lead lag calculations to be updated and incorporated into the working capital schedules and would require the budget payment plan figures to be updated. The deemed income tax schedules would also require updating.

Regulatory costs

The AUC approved the continuation of the hearing cost reserve accounts for 2019 for the DRT and the RRT. The AUC considered that customers should only pay the AUC-approved costs for participation in regulatory proceedings.

Because the cost claim for this 2019 DRT and RRT application was filed in October 2019 in Proceeding 24957 and a 90-day deadline for the decision to be issued on the cost claim would result in the decision being issued in 2020, this meant that DERS would not be authorized to pay any of the approved costs for this proceeding from its hearing cost reserve account until 2020. Accordingly, the AUC held that the $0.850 million forecast payments for 2019 for this proceeding should be removed from the hearing cost reserve account for 2019 and may be included as part of the hearing cost reserve account for 2020.

Other administration costs

The AUC was not prepared to test DERS' decision to incur costs for a benchmarking study to set the FMV for customer care and billing services for 2020, nor for the services of a consultant to assist in selecting a new CC&B service provider. Accordingly, the AUC held it was not reasonable to approve any of the forecast costs associated with these activities for inclusion in the 2019 DRT and RRT revenue requirements. The AUC accordingly directed DERS, in the compliance filing to this decision, to reduce the other administration costs for 2019 by $415,000, allocated between the DRT and the RRT.

Corporate services costs

The AUC found that DERS did not provide the required more detailed information about corporate services costs. The AUC requires information regarding how costs are allocated from Centrica plc, of which DEML is a subsidiary, to North America Home ("NAH") and additional information regarding how costs are allocated from NAH to the Canadian line of business.

AUC Order

The AUC ordered that:

(a) DERS will submit a compliance filing to this decision to reflect the AUC's findings and directions, on or before January 8, 2020;

(b) the DRT rate schedules and RRT schedules for DERS, as set out in appendices to the decision are approved on an interim basis, effective January 1, 2020;

(c) the DRT return margin charge of $0.045 per gigajoule for DERS is approved on an interim basis, effective January 1, 2020;

(d) the DRT charge of $0.010 per gigajoule for the energy-related portion of credit charges, working capital, bad debt and late payment charges for DERS is approved on an interim basis, effective January 1, 2020;

(e) the DRT monthly amount of $30,334 for labour related to gas procurement for DERS is approved on an interim basis, effective January 1, 2020;

(f) the DRT rate schedules for DERS, as set out in appendices to the decision, are approved on an interim basis, effective April 1, 2020;

(g) the RRT rate schedules for DERS, as set out in an appendix to the decision, are approved on an interim basis, effective April 1, 2020;

(h) the terms and conditions of DRS for DERS, as set out in an appendix to the decision, are approved, effective December 5, 2019; and

(i) the terms and conditions of regulated rate service for DERS, as set out in an appendix to the decision, are approved, effective December 5, 2019.

EDP Renewables SH Project GP Ltd. Sharp Hills Wind Project Amendments (AUC Decision 24401-D01-2019)

Wind Projects - Rule 012 - Noise Control

In this decision, the AUC considered whether to approve applications from EDP Renewables SH Project GP Ltd. ("EDP") for amendments to a power plant and substation, collectively designated as the Sharp Hills Wind Project. The AUC found that approval of the proposed amendments to the project were in the public interest.

<u>Amendment application description</u>

EDP had approval to construct and operate the Sharp Hills Wind Project in the New Brigden and Sedalia areas.

On March 8, 2019, EDP filed applications with the AUC for approval to amend the Sharp Hills Wind Project, including alterations to the Sharp Hills Wind Farm and the Sedalia 363S Substation. Specifically, EDP applied for amendments including a change in turbine model. As a result, 12 turbines were removed from the original project layout and adjustments were made to the collector system, access roads and transformers in the Sedalia 363S Substation. EDP also adjusted the project to be developed in two phases.

<u>Issues raised in the proceeding</u>

The AUC's recent amendments to Rule 012 - *Noise Control* came into effect on August 1, 2019. One of the amendments found in the current version of Rule 012 is a new section (section 2.6) that expressly addresses ambient sound levels ("ASLs").

The previous and current versions of Rule 012 give applicants two options for establishing ASLs and permissible sound levels ("PSLs") at receptors:

- if the assumed ASLs and PSLs set out in Table 1 of Rule 012 are representative of the project study area (at receptors), an applicant may use those assumed values; and

- if the project area is located in a pristine area or an unusually noisy area and the assumed ASLs and PSLs set out in Table 1 of Rule 012 are not representative of the project study area (at receptors), an applicant can rely on measurements to determine the ASL. Where a measured ASL is used, a Class A2 adjustment (also called an ambient monitoring adjustment) is established based on the measured ASL and then applied to the PSL.

The primary issue raised in this proceeding was whether it was reasonable for EDP to use an assumed nighttime ASL of 35 dBA (based on Table 1 of Rule 012) when calculating the PSLs at various receptors in the project area.

AUC findings

The AUC noted that Rule 012 originated with Alberta Energy Regulator Directive 038: Noise Control. Directive 038 sets an assumed nighttime ASL of 35 dBA for rural areas and states, "[b]ased on research conducted by the Environment Council of Alberta, the average rural ambient sound level in Alberta is about 35 dBA at night."

Assumed ASLs can be used by applicants, and Directive 038 notes that the only two cases where it may be necessary to determine ambient sound level are areas considered to be pristine and areas with non-energy industrial activity that would impact the background noise levels.

Rule 012's definition of pristine area is "a natural area that might have a dwelling but no industrial presence, including energy, agricultural, forestry, manufacturing, recreational or other industries that affect the noise environment."

The intervenors argued that their area was pristine, and that downward adjustments to the ASL was required based on the sound study that had been conducted by their expert.

The AUC found that the evidence presented by the intervenors was not sufficient to demonstrate that the project area was pristine or that the ASL in the project area was materially different than other parts of rural Alberta, where oil and gas and agricultural activities also take place.

Rather, the AUC found EDP's description of the project area as "typical of rural Alberta with predominate agricultural and energy industry land use" to be accurate. Given the presence of agricultural and oil and gas activities throughout the project area, the AUC found that it was reasonable for EDP to conclude that the assumed ASLs based on Table 1 of Rule 012 were representative of the project area.

Representative conditions for the measurement of ambient sound levels

The AUC provided further comment on measurement duration and data transferability. It found that 24 hours of measurement data was inadequate to establish representative ASLs in circumstances where there were no constant dominant sound sources.

With regard to data transferability, the AUC noted that Rule 023 allows measurement data collected at one receptor to be used to establish ASLs at other receptors in a similar acoustic environment. However, in this case, there was inadequate measurement duration, and there were other questions regarding whether data measured at one location was representative of another location.

Rule 12 compliance and noise impacts

The AUC found that the use of assumed ASLs based on Table 1 of Rule 012 was appropriate for these applications, and the nighttime PSL for the affected receptors, including the intervener residences, was 40 dBA (5 dBA above the ASL). Based on the results of the project Noise Impact Assessment, the AUC found that cumulative sound levels at all affected noise receptors will likely comply with that nighttime PSL.

Post-construction comprehensive sound level surveys

Given the concerns raised by intervenors, the AUC required that EDP complete a comprehensive sound level survey to verify compliance with Rule 012 once the project commences operation.

ENMAX Power Corporation 2020 Annual Performance-Based Regulation Rate Adjustment (AUC Decision 24875-D01-2019)

Performance-Based Regulation

In this decision, the AUC considered ENMAX Power Corporation ("ENMAX")'s 2020 annual performance-based regulation ("PBR") rate adjustment filing. The AUC made the following determinations:

- the adjustments to the interim notional 2017 revenue requirement and 2018 base K-bar for the 2018-2022 PBR plan for ENMAX were approved. However, these amounts would remain interim since certain placeholders remain unresolved;

- the interim 2020 electric distribution service base rates and the corresponding rate schedules, with adjustments for 2018 and 2020 K-bar, Type 1 capital, line loss reduction program, 2018 hybrid deferral account, and Y factor, were approved effective January 1, 2020;

- a distribution access service ("DAS") adjustment rider refund was approved in the amount of $2.10 million effective January 1, 2020 to March 31, 2020; and
- distribution tariff terms and conditions were approved effective January 1, 2020.

Background and application

On September 10, 2019, ENMAX submitted its 2020 annual PBR rate adjustment filing to the AUC, requesting approval of its 2020 electric distribution service rates and the corresponding rate schedules, to be effective January 1, 2020, on an interim basis. ENMAX also requested approval of its distribution tariff terms and conditions ("T&Cs") of electric distribution service, to be effective January 1, 2020.

Adjustments to the interim notional 2017 revenue requirement and 2018 base K-bar

In Decision 21508-D01-2017 the AUC approved ENMAX's 2017 forecast capital tracker amounts as part of a negotiated settlement agreement. Subsequently, in Decision 23694-D01-2019, the AUC approved a true-up of the 2017 forecast amounts on an actual basis, and the resultant actual K factors, by way of approving an additional NSA.

In the present proceeding, ENMAX explained that Decision 23694-D01-2019 affected ENMAX's notional 2017 revenue requirement necessitating adjustments to its 2018 and 2019 rates.

ENMAX proposed a number of adjustments. In aggregate, these adjustments resulted in a 2018 K-bar true-up of ($0.61) million and associated carrying costs of ($0.04) million.

The AUC considered the adjustments made to the notional 2017 revenue requirement and 2018 base K-bar amounts to be generally in alignment with the Commission's findings in Decision 21508-D01-2017 and Decision 23694-D01-2019. The AUC approved the resultant adjustments to the interim notional 2017 revenue requirement and 2018 base K-bar as filed. However, the AUC observed that these amounts would remain interim pending AUC determinations in Proceedings 23966, 24325, and 24761.

I factor and the resulting I-X index

The AUC reviewed ENMAX's calculations and approved the I factor of 1.36 per cent and the resulting I-X index value of 1.06 per cent for 2020.

K-bar factor

The AUC approved ENMAX's 2020 K-bar in the amount of $18.29 million. This amount remained interim pending finalization of all actual capital tracker amounts incurred during the 2015-2017 PBR term. The 2020 K-bar will be subject to a further true-up for the 2020 actual approved cost of debt.

Type 1 capital

ENMAX had one Type 1 capital placeholder. The AUC approved ENMAX's placeholder request for cost recovery of 90 per cent of the management-approved internal 2019 forecast of $18.81 million in capital additions for the costs associated with relocation of ENMAX's infrastructure in years 2020 through 2022, pursuant to The City of Calgary's Green Line Light Rail Transit ("LRT") project and the corresponding incremental revenue requirement of the 90 per cent placeholder in the amount of $1.02 million.

ENMAX requested approval of a Type 1 capital placeholder for the 2020 revenue requirement amount of $1.25 million associated with the Green Line LRT project. The AUC approved the 2020 revenue requirement in the amount of $1.25 million for the Green Line LRT project as filed, subject to the AUC's ultimate determination as to whether this project meets the Type 1 capital criteria and the expenditures are prudent in the true-up application that ENMAX indicated would be filed in 2020.

Distribution line loss reduction program true-up

The AUC reviewed ENMAX's schedules pertaining to the line loss reduction program costs and savings. The AUC noted that the net savings amount would be equally shared between ENMAX and its customers.

The AUC found that the 2018 true-up difference of $0.81 million results from the previously approved forecast of $0.71 million in Decision 23355-D02-2018 and the actual data of $1.52 million. The AUC approved ENMAX's applied-for line loss reduction program savings adjustment as filed.

The AUC noted that ENMAX's line loss reduction program ended on December 31, 2018, concluding a 10-year approved term. Therefore, the 2018 adjustment considered in this proceeding is the final adjustment for the program under this term.

Y and Z factor materiality threshold

The AUC approved ENMAX's Y and Z factor materiality threshold to be $1.87 million for 2020 on an interim basis. As set out in Decision 20414-D01-2016 (Errata), this interim threshold amount will be finalized upon approval of the final notional 2017 revenue requirement.

Y factor

The AUC noted that the Y factor costs applied for were of a type that the AUC approved for Y factor treatment in Decision 20414-D01-2016 (Errata). The Y factor amounts were approved.

Forecast billing determinants and Q

ENMAX reconciled forecast and actual billing determinants from 2018. There were variances larger than ± five per cent for energy consumption in residential, small commercial and large commercial primary rate classes due to more heating degree days and cooling degree days than initially forecast. There were also variances larger than ± five per cent for a number of sites and energy consumption in the large distributed generation rate class due to energizing an additional two sites that were not forecast. Finally, there was a larger than ± five per cent variance for energy consumption in the street lighting rate class. ENMAX stated that "the increase in energy consumption is due to the increased number of fixtures than initially anticipated."

The AUC considered that variances from forecasts resulting from circumstances such as those described by ENMAX for 2018 were reasonable.

The 2020 forecast billing determinants were approved as filed. The AUC also approved ENMAX's 2020 Q of 0.63 percent. The AUC directed ENMAX to continue providing Q value calculations in its future annual PBR rate adjustment filings.

Distribution rates

The AUC accepted the general principles and methodologies utilized by ENMAX for calculating its 2020 PBR rates.

The AUC also reviewed the typical bill impacts from December 2019 to January 2020, and observed that the month-over-month decreases to customer bills from December 2019 to January 2020, were not expected to exceed 10 per cent for all rate classes.

The AUC approved ENMAX's 2020 PBR rates on an interim basis, effective January 1, 2020.

Distribution access service ("DAS") adjustment rider

ENMAX requested approval to include a DAS adjustment rider to reconcile amounts related to 2015-2016 K factor true-up, 2018-2019 base rates true-up and 2019 DAS adjustment rider true-up. The AUC approved the DAS adjustment rider refund in the amount of $2.10 million, as filed, and ENMAX's proposal of implementing the rider adjustment over the three-month period, from January 1 to March 31, 2020.

ENMAX's hybrid deferral account proposal

ENMAX proposed to capture any changes to historical AESO contribution amounts through a true-up mechanism by way of a deferral account, with the properties of K-bar continuing to provide incremental capital funding for new AESO contributions. ENMAX outlined specifics of the deferral account methodology as follows:

- projects from the 2015-2017 PBR term where a permit and licence ("P&L") had been issued by December 31, 2017, would be subject to deferral account treatment by way of a new PG5 Deferral Account; and

- projects that receive P&L after December 31, 2017, would be managed under the incentive properties of K-bar.

The AUC accepted ENMAX's proposal with the qualification that projects, including any project changes, that had received a P&L during the 2015-2017 PBR term shall be given deferral account treatment provided that the AUC has approved the need, scope, level, timing and associated costs for the project as part of capital tracker review, including by way of approving a negotiated settlement agreement. Projects that receive permit and licence after December 31, 2017, shall be managed under the incentive properties of K-bar.

ENMAX Power Corporation 2020 Balancing Pool Allocation Rider (AUC Decision 25009-D01-2019)

Balancing Pool Allocation Rate Rider

In this decision the AUC considered an application filed on October 21, 2019 by ENMAX Power Corporation ("EPC") requesting approval of its 2020 Balancing Pool allocation rider. The AUC approved EPC's 2020 Balancing Pool allocation rider as filed, effective January 1, 2020.

Background

Under the *Electric Utilities Act* ("*EUA*"), the benefits and costs associated with the Balancing Pool are shared among all electricity customers in Alberta. Accordingly, each year the Balancing Pool is required to forecast its revenues and expenses to determine any excess (or shortfall) of funds. Based on this forecast, the Balancing Pool determines an annualized amount that will be remitted to or collected from electricity consumers over the year. Pursuant to Section 82 of the *EUA*, these distributions or charges are made through the Alberta Electric System Operator ("AESO") tariff, by way of Rider F.

The allocation among participants is based on the amount of electric energy consumed annually. Because the AESO's Rider F is calculated at the substation point of delivery ("POD") level and a utility's Balancing Pool allocation rider is applied at the customer meter level, in calculating a utility's Balancing Pool allocation rider, the AESO's charge rate must be adjusted to account for distribution losses.

AUC findings

The AUC found that, consistent with the methodology used and approved in Decision 24091-D01-2018, EPC calculated its 2020 Balancing Pool allocation rider based on the AESO's 2020 Rider F consumer allocation charge of $2.50/MWh, adjusted for EPC's estimated 2020 distribution losses. This resulted in a slightly higher Balancing Pool charge at the EPC distribution level than the $2.50/MWh charge under the AESO's Rider F.

The AUC reviewed the calculations of the 2020 Balancing Pool allocation rider rates based on the 2020 energy forecast at the customer meter from the 2020 annual performance-based regulation filing, and the POD forecast based on the applied-for line loss factor in Proceeding 24820, and found these assumptions to be reasonable and the calculations correct.

The AUC approved EPC's 2020 Balancing Pool allocation rider, effective January 1, 2020. In making this determination, the AUC noted it is mindful that EPC's 2020 Balancing Pool allocation rider would eventually be trued up to ensure the approved amounts were collected from customers.

ENMAX Power Corporation 2020 Interim Transmission Facility Owner Tariff (AUC Decision 25019-D01-2019)

Rates - Interim Transmission Facility Owner Tariff

In this decision, the AUC considered whether to approve the ENMAX Power Corporation ("ENMAX") October 24, 2019 application (the "Application") for a 2020 interim transmission facility owner tariff in the amount of $99.77 million to be collected by way of a monthly rate of $8.31 million effective January 1, 2020. The AUC approved the Application.

Background

ENMAX filed its 2018-2020 transmission general tariff application ("GTA") with the AUC on December 12, 2018. ENMAX submitted that it is unlikely that a final transmission tariff would be approved before the third quarter of 2020.

ENMAX indicated that the proposed 2020 interim tariff was intended to reduce the increase that would otherwise result from the future implementation of a final 2020 tariff, by collecting 60 per cent of the revenue shortfall over the period of time commencing January 1, 2020, until the interim tariff is replaced by a revised interim or final 2020 tariff.

AUC findings

In Decision 2005-099, the AUC's predecessor (the Alberta Energy and Utilities Board) established a test to evaluate interim rate applications.

The first part of the test relates to quantum and need factors, and includes the following considerations:

(a) the identified revenue deficiency should be probable and material;

(b) all or some portion of any contentious items may be excluded from the amount collected;

(c) is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?

(d) can the applicant continue safe utility operations without the interim adjustment?

The second part of the test relates to the public interest and includes the following considerations:

(a) interim rates should promote rate stability and ease rate shock;

(b) interim adjustments should help to maintain intergenerational equity;

(c) can interim rate increases be avoided through the use of carrying costs?

(d) interim rate increases may be required to provide appropriate price signals to customers; and

(e) it may be appropriate to apply the interim rider on an across-the-board basis.

With respect to the quantum and need factors, the AUC found that the revenue shortfall of $16.48 million projected by ENMAX for 2020 in the absence of the interim adjustment is material and is probable. Further, due to the timing of ENMAX's GTA and associated compliance filing, final rates for ENMAX are not likely to be in place before the middle of 2020.

The AUC also found that ENMAX's request to recover 60 per cent of its 2020 revenue shortfall was reasonable as it removed revenue amounts associated with any contentious or settled items in its GTA and excluded them from the amount proposed to be collected on an interim basis.

With respect to the public interest factors articulated in the second part of the test, the AUC found that the collection, beginning January 1, 2020, of a portion of any rate increase resulting from ENMAX's final 2020 tariff, promotes rate stability through a gradual rate increase. Therefore, ENMAX's proposed 2020 interim tariff would help to levelize the transmission tariff in 2020, maintain intergenerational equity and reflect the correct price signal.

Overall, the AUC found that ENMAX's proposed 2020 interim transmission tariff achieved a reasonable balance among the considerations of the two-part test.

AUC Order

The AUC ordered that ENMAX's 2020 interim transmission facility owner tariff in the amount of $99.77 million is approved, to be collected by way of a monthly rate of $8.31 million, effective January 1, 2020, on an interim basis.

ENMAX Power Corporation Compliance Filing to Decision 23102-D01-2019 (AUC Decision 24761-D01-2019)

Compliance Filing - Capital Tracker Treatment of Project Expenditures

In this decision the AUC considered the ENMAX Power Corporation ("ENMAX") application (the "Application") regarding its compliance with the Commission's directions issued in Decision 23102-D01-2019. The AUC found that ENMAX complied with the AUC's directions in its Application. However, the Commission made the following determinations:

- ENMAX's actual K factor amounts related to 2015 and 2016 and the specifics (e.g., timeframe) of how the distribution access service ("DAS") rider will be implemented will not be decided in this proceeding; instead the Commission will make its determinations in Proceeding 24875.

- The PG4-A-4 Proactive Cable Replacement and PG4-A-8 Overhead Conductor Replacement project costs incurred in 2017 are not eligible for capital tracker treatment, these expenditures will not be funded through the K factor provision of the performance-based regulation ("PBR") formula and are to be accounted for under I-X. ENMAX is directed to refile the accounting test for the PG4 Program reflecting the removal of the 2017 capital additions for the PG4-A-4 ("PG4-A-4") and PG4-A-8 capital tracker projects ("PG4-A-8") in its 2021 PBR annual rate adjustment filing.

Background

On March 1, 2019, the AUC issued Decision 23102-D01-2019 (the "METSCO Decision"). In the METSCO Decision, the AUC issued four directions to ENMAX, including Direction 1, that is a summary of the AUC directions:

> ... ENMAX is directed to file an application with the Commission that:
>
> • Re-runs the accounting test for the PG4 Program reflecting the revised capital tracker capital additions for 2015 and 2016 for the PG4-A-4 and PG4-A-8 projects. [Direction 2]
>
> • Proposes how ENMAX plans to adjust rates based on any difference in K factor amounts that were already collected based on Decision 23355-D01-2018, and the K factor amounts calculated based on the directions in this decision. [Direction 2]
>
> • Requests approval of its 2017 actual capital additions for capital tracker treatment with respect to the PG4-A-4 and PG4-A-8 projects, given that these amounts were excluded from the negotiated settlement process in Proceeding 23694. [Direction 3]
>
> • Capital tracker true-up of ENMAX's PG4-A-4 and PG4-A-8 capital tracker projects for 2017. Compliance with all other directions in Decision 23102-D01-2019 [Direction 3]

Direction 4 required EPC to file a compliance filing with respect to the above on or before May 27, 2019.

Direction 2: PG4-A-4 and PG4-A-8 capital tracker projects in 2015 and 2016

The two capital tracker projects, PG4-A-4 and PG4-A-8, are part of ENMAX's larger PG4 Program, which has a focus on capital maintenance. PG4-A-4 consists of replacement or rejuvenation of pre-1989 medium voltage cross linked polyethylene underground cables and modification or relocation of facilities in light of customer or government requests. PG4-A-8 involves the replacement of small primary overhead conductors that have proven to be prone to breaking and falling to the ground.

The AUC reviewed ENMAX's calculations of removing the 2015 and 2016 capital addition amounts for the PG4-A-4 and PG4-A-8 capital tracker projects and found them to be in compliance with Direction 2 of the METSCO Decision.

Further, the AUC considered ENMAX's proposal to refund the K factor amounts by way of the distribution access service ("DAS") rider to be reasonable. However, the AUC noted that at the time of this decision, this proposal was also being considered by the AUC in Proceeding 24875. Therefore, the actual K factor amounts related to 2015 and 2016 and the specifics (e.g., timeframe) of how the DAS rider would be implemented was not considered in this proceeding.

Direction 3: Capital tracker true-up of EPC's PG4-A-4 and PG4-A-8 capital tracker projects for 2017

In the METSCO Decision the AUC directed ENMAX to apply for approval of capital tracker treatment of its 2017 actual capital expenditures for the PG4-A-4 and PG4-A-8 projects as part of the compliance filing to that decision.

In order to be eligible for capital tracker treatment, a project must meet the three criteria established in Decision 2012-237, the first of which, Criterion 1, is that the project must be outside the normal course of the company's ongoing operations. Criterion 1 includes two sub-parts: an accounting test, and a project assessment test. The project assessment test was the only aspect of the capital tracker criteria at issue in this proceeding, since the other criteria relate to ENMAX's negotiated settlement agreement, approved by the AUC in Decision 21508-D01-2019.

The project assessment test requires the AUC to assess whether the project is: required to provide utility service at adequate levels; and, if so, whether the scope, level and timing of the project are prudent, and whether the forecast or actual costs of the project are reasonable.

The AUC found that ENMAX had not met its burden of proof in establishing the prudence of the scope, level and timing, and the actual costs for PG4-A-8 Project in 2017. Accordingly, the AUC would not extend capital tracker treatment to EPC's actual 2017 costs associated with PG4-A-8 Project.

Order

The AUC ordered that ENMAX calculate the 2017 K factor true-up adjustment amount arising from this decision in its 2021 performance-based regulation annual rate adjustment filing.

The AUC noted that ENMAX's actual K factor amounts related to 2015 and 2016 and the specifics of how the DAS rider will be implemented would not be decided in this proceeding; but in Proceeding 24875.

The AUC ordered that the PG4-A-4 and PG4-A-8 Project costs incurred in 2017 were not eligible for capital tracker treatment, and therefore these expenditures would not be funded through the K factor provision of the performance-based regulation formula and are to be accounted for under I-X.

The AUC directed ENMAX to refile the accounting test for the PG4 Program reflecting the removal of the 2017 capital additions for the PG4-A-4 and PG4-A-8 capital tracker projects in its 2021 PBR annual rate adjustment filing.

EPCOR Distribution & Transmission Inc. 2020 Annual Performance-Based Regulation Rate Adjustment (AUC Decision 24882-D01-2019)

Performance-Based Regulation

In this decision, the AUC considered the 2020 annual performance-based regulation ("PBR") rate adjustment filing of EPCOR Distribution & Transmission Inc. ("EPCOR" or "EDTI"). The AUC approved the following:

- the 2020 distribution access service ("DAS") tariff, on an interim basis;
- the 2020 transmission system access service ("SAS") tariff;
- 2020 Balancing Pool Rider G;
- the customer and retailer terms and conditions ("T&Cs") for electric DAS; and
- 2020 distribution tariff policies.

<u>Background and application</u>

On September 10, 2019, EPCOR submitted its 2020 annual PBR rate adjustment filing to the AUC, requesting approval of its 2020 electric DAS rates, Y and Z factor adjustments, riders, SAS rates, billing determinants and corresponding rate schedules to be effective January 1, 2020, on an interim basis. EPCOR also requested approval of its T&Cs and distribution tariff policies of electric distribution service, to be effective January 1, 2020.

<u>Adjustments to the interim notional 2017 revenue requirement and 2018 base K-bar</u>

The AUC noted that there are three ongoing AUC proceedings that have the potential to impact EPCOR's notional 2017 revenue requirement or 2018 base K-bar. The notional 2017 revenue requirement and 2018 base K-bar will remain interim until each of decisions are released in Proceedings 24325, 24609, and 24980.

<u>I factor and the resulting I-X index</u>

The Commission found that any revised values after August 2019 were not appropriate for use in this year's I factor calculation.

The AUC found that EPCOR used the correct Statistics Canada data, and approved the I factor of 1.36 per cent and the resulting I-X index value of 1.06 per cent for 2020.

<u>K-bar factor</u>

The AUC approved EPCOR's 2020 K-bar in the amount of $25.04 million. This amount would remain interim pending finalization of all actual capital tracker amounts incurred during the 2013-2017 PBR term and any updated depreciation parameters. The 2020 K-bar would be subject to a further true-up for the 2020 actual approved cost of debt.

<u>Y and Z factor materiality threshold</u>

The AUC calculated EPCOR's Y and Z factor materiality threshold to be $1.72 million for 2019. The AUC calculated this amount based on the 2019 interim Z factor materiality threshold approved in Decision 23896-D01-2019 and escalated it by the 2020 I-X index, in accordance with the methodology prescribed in Decision 20414-D01-2016 (Errata). EPCOR's 2020 Y and Z factor materiality threshold was set at $1.72 million on an interim basis. This interim threshold amount would be finalized upon approval of the final notional 2017 revenue requirement.

<u>Y factor</u>

The AUC noted that the Y factor costs applied for were of a type that the AUC approved for Y factor treatment in Decision 20414-D01-2016 (Errata). The Y factors were approved.

Forecast billing determinants and Q

The AUC found that the methodology and the resulting 2020 forecast billing determinants were reasonable. The AUC directed EPCOR to continue using the forecasting methodology as filed for the remainder of the PBR term unless directed by the Commission. The 2020 forecast billing determinants are approved as filed.

The AUC also reviewed EPCOR's calculation of its 2020 Q value and found it to be reasonable. The AUC therefore approved EPCOR's 2020 Q of 0.39 percent. The AUC directed EPCOR to continue providing Q value calculations in its future annual PBR rate adjustment filings.

2019 CS49 notional base rate

On June 14, 2019, EPCOR filed an application with the AUC requesting approval for a 2019 customer specific DAS rate for a new customer (CS49), which the Commission approved.

The AUC reviewed EPCOR's calculations of its adjusted 2019 base rate for the CS49 customer, and found it consistent with earlier AUC decisions and directions, and approved base rates for other customers. The AUC therefore approved the 2019 base rate for the CS49 customer as $509.71 per day on an interim basis.

CS46 rate true-up

The AUC reviewed EPCOR's calculations for the true-up to the CS46 rate to reflect the 2018 actual weighted average cost of capital rate of 6.20 per cent and agreed with the methodology and accuracy of the calculated results. The AUC therefore approved the CS46 true-up refund to customers as calculated by EPCOR of $2,131.51.

SAS rates

EPCOR requested approval of its 2020 SAS rates, to be effective January 1, 2020. EPCOR indicated that its 2020 SAS rates reflect the AESO's 2018 Independent System Operator ("ISO") tariff approved in Decision 23065-D01-2017.

EPCOR proposed to continue to collect the Balancing Pool rebate as a separate rider (Rider G) to its SAS rates.

The AUC approved EPCOR's 2020 SAS rates and 2020 Balancing Pool Rider G.

DAS rates

The AUC noted that, on a total bill basis, bill impacts would be below 10 percent; a threshold that the AUC has determined in past decisions to be indicative of possible rate shock. The AUC reviewed EPCOR's calculation of its 2020 DAS rates, 2020 miscellaneous service fees, 2020 SAS rates, and Rider G, and approved them on an interim basis, effective January 1, 2020.

It held that the 2020 rates shall remain interim until the remaining placeholders and the issue of anomalies in relation to EPCOR's going-in rates have been addressed by the AUC.

EPCOR Energy Alberta GP Inc. Arrangement to Provide Regulated Rate Option Service in the Distribution Service Area of FortisAlberta Inc. (AUC Decision 24839-D01-2019)

Regulated Rate Option Service

In this decision, the AUC considered an application from EPCOR Energy Alberta GP Inc. ("EEA") requesting approval of the arrangement under which EPCOR Energy Alberta GP Inc. would provide regulated rate option ("RRO") service to eligible customers within FortisAlberta Inc.'s distribution service area. The AUC approved the proposed RRO arrangement agreement (the "RRO Arrangement Agreement") as filed.

Background

EEA currently provides RRO service within the Fortis service area pursuant to the terms of the current arrangement agreement, which was approved by the Alberta Energy and Utilities Board (the "Board"), the AUC's predecessor, in Decision 2000-71, and in accordance with subsequent decisions and events affecting the names and structure of the signing parties.

EEA provided an explanation of the differences between the current agreement and the proposed RRO Arrangement Agreement. These included updated legislative references, new provisions for the event of early expiry or termination, ongoing governance and reporting of EEA's obligations and the handling of customer data, and an expanded scope of indemnity.

For each of the differences, EEA submitted there would be no effect on RRO customers, with the exception of changes covering the effect of expiration or early termination and changes to governance and reporting. With respect to expiration or early termination, EEA explained that RRO customers will benefit from the clear and sensible provisions that facilitate a smooth transition of the RRO obligations back to Fortis in the event the proposed RRO Arrangement Agreement expires or is terminated early. With respect to governance and reporting, EEA submitted that RRO customers will benefit from the parties having clear expectations around governance and reporting.

Legislative provisions

The AUC outlined the applicable sections of the *Electric Utilities Act* (*"EUA"*) and the *Regulated Rate Option Regulation* (*"RRO Regulation"*) which relate to an electric distribution system owner's ability to enter into an arrangement for another party to provide RRO service on the owner's behalf. These included sections 104(1) and 105(1) of the *EUA* which sets out the duties and ongoing obligations of owners of electric distributions systems, and section 20 of the *RRO Regulation,* which sets out the requirement that the AUC approve RRO agreements like the one contemplated in this application.

Criteria to be applied respecting the authorization of an RRO Arrangement Agreement

The AUC noted that a public interest test is applied when reviewing approvals to RRO arrangement agreements. It cited Decision 2000-71, where the Board indicated that in order to preserve the public interest, the Board should be satisfied that, on balance, customers will at least be no worse off after the transaction, or suffer "no harm" as a result of the arrangement. Other factors to be considered when assessing such an application include:

- whether the liability for provision of service remains with the owner;
- whether there is a potential impact to rates, and whether the impact is just and reasonable;
- the provision of safe, reliable and economic delivery of electric energy;
- compliance with the Code of Conduct Regulation, and the Inter-Affiliate Code of Conduct;
- the fair, efficient and openly competitive principle; and
- the other duties of owners of electric distribution systems and their authorized service providers under the *Electric Utilities Act*, *RRO Regulation* and other applicable legislative provisions.

Compliance with applicable enactments and rules

The AUC found that the proposed RRO Arrangement Agreement was consistent with the legislative duties of the owner of the distribution system and the person authorized to perform any or all of the duties or functions of the owner.

No-harm test

The AUC found that there are regulatory safeguards embodied in the AUC's broad regulatory authority over the provision of RRO service and the legislative framework governing the RRO in Alberta, to ensure that no harm should arise from the continuation of EEA as the RRO service provider in the Fortis service area.

The AUC was satisfied that the "no-harm" standard required to be applied in applications of this kind were met, and that EEA discharged its onus in this regard.

Order

The AUC approved the agreement setting out the terms of the arrangement under which EEA in its capacity as the general partner of EPCOR Energy Alberta Limited Partnership, will provide RRO service to eligible customers within FortisAlberta Inc.'s distribution service area, effective on January 1, 2021, and expiring on December 31, 2040.

FortisAlberta Inc. 2020 Annual Performance-Based Regulation Rate Adjustment (AUC Decision 24876-D01-2019)

Performance-Based Regulation

In this decision, the AUC considered FortisAlberta Inc.'s 2020 annual performance-based regulation ("PBR") rate adjustment filing. The AUC made the following determinations:

- the adjustments to the interim notional 2017 revenue requirement and 2018 and 2019 base K-bar for the 2018-2022 PBR plans for

Fortis were approved. However, these amounts remain interim since certain placeholders remain unresolved;

- the 2020 rates, options and riders schedules were approved effective January 1, 2020, on an interim basis; and
- the customer and retailer terms and conditions of electric distribution service were approved effective January 1, 2020.

Background and Application

On September 13, 2019, Fortis submitted its 2020 annual PBR rate adjustment filing, requesting approval of its 2020 rates, options and rider schedules, to be effective January 1, 2020, on an interim basis. Fortis also requested approval of its customer and retailer terms and conditions ("T&Cs") of electric distribution service, to be effective January 1, 2020.

Adjustments to the interim notional 2017 revenue requirement

The AUC approved the notional 2017 revenue requirement; however, it noted that these amounts would continue to remain interim pending the finalization of all outstanding placeholders such as the AUC determinations arising from Proceeding 24325, the AUC's recent Decision 24281-D01-201917 and ongoing consideration of Proceeding 24932, and Decision 23961-D01-2019.

Adjustment to K-bar revenue requirement

Fortis updated its K-bar for 2018 and 2019, with 2018 K-bar lowered by $0.3 million, and 2019 K-bar increased by $1.8 million. The AUC approved the resulting 2018 and 2019 K-bar revenue, which continued to remain interim pending the finalization of all outstanding placeholders that remain the subject of ongoing proceedings or recent decisions that were not, by virtue of their timing, reflected in Fortis' application.

I Factor and the resulting I-X index

The AUC approved the I factor of 1.36 per cent and the resulting I-X index value of 1.06 per cent for 2020.

K Factor

Fortis proposed to refund $0.027 million in K factor revenue, and the Commission approved its proposal.

K-bar Factor

The AUC approved Fortis' 2020 K-bar in the amount of $58.4 million. This amount remains interim and may be subject to further true-up based on the outcome of the proceedings identified earlier in the decision. The 2020 K-bar will be subject to a further true-up for the 2020 actual approved cost of debt.

AESO contributions hybrid deferral account

The AUC reviewed the schedule showing the revenue requirement associated with the AESO contribution hybrid deferral account and found that Fortis complied with the AUC's directions from Decision 23505-D01-2018 as it relates to this proceeding. The AUC approved the resulting revenue requirement that Fortis has included in its 2020 PBR rates; however, noted that these rates would continue to remain interim.

Y and Z factor materiality threshold

The AUC established Fortis' Z factor materiality threshold to be $4.74 million for 2020 on an interim basis. This interim threshold amount would be finalized upon approval of the final notional 2017 revenue requirement.

Y Factor

The AUC approved Y factor treatment in Decision 24405-D01-2019 for the Crows Nest Pass and Town of Fort Macleod acquisitions, and approved Y factor true-ups associated with them.

Regarding the remainder of the Y factor amounts, all of these costs were of a type that the AUC approved for Y factor treatment in Decision 20414-D01-2016 (Errata). Fortis' Y factor amounts were approved, as filed.

Forecast billing determinants and Q

The AUC approved Fortis' proposed changes to its forecasting methodology for the exterior lighting rate class and directed Fortis to continue using this forecasting methodology for the remainder of the PBR term unless otherwise directed by the

Commission. The 2020 forecast billing determinants are approved as filed.

The AUC also approved Fortis' 2020 Q of 0.12 per cent.

System access service rates

The AUC reviewed Fortis' calculation of its proposed transmission access cost forecast for 2020. It was based on the AESO's 2019 Demand Transmission Service tariff update, approved by the AUC on an interim basis, effective January 1, 2019, in Decision 24036-D01-2018, and was reflective of the pool price and operating reserve percentage forecast based on Fortis' actual monthly average from August 2018 to July 2019. The AUC therefore found Fortis' proposed transmission access cost forecast for 2020 to be reasonable.

Fortis allocated these costs to rate classes based on previously approved methodologies and assumptions, and the AUC approved the resulting 2020 system access service rates as filed.

Distribution rates

The AUC noted that, on a total bill basis, bill impacts will be below 10 per cent; a threshold that the AUC had determined in past decisions to be indicative of possible rate shock.

The AUC also reviewed Fortis' 2020 PBR rate calculations and found that the proposed January 1, 2020, PBR rates were calculated in accordance with the provisions of Fortis' Commission-approved PBR plan. Accordingly, the AUC approved Fortis' 2020 PBR rates, on an interim basis, effective January 1, 2020.

The AUC held that the 2020 rates shall remain interim until the remaining placeholders and the issue of anomalies in relation to the utility's going-in rates have been addressed by the AUC.

LED conversion maintenance multiplier

The AUC approved the proposed change in the LED maintenance multiplier percentage from 1.09 to 1.08, effective January 1, 2020.

Rate schedule wording amendment for Option D

Fortis requested to amend the wording in Appendix E – 2020 Rates, Options and Riders Schedules, for Option D – Flat Rate Option, on an interim basis, until such time as it is reviewed in Fortis' next Phase II application. Fortis proposed to add the following wording to Option D, "2. For new Points of Service only: Upon agreement with and at the discretion of FortisAlberta, virtual aggregation and grouping of small connected devices (which may be physically disparate) can be represented as a single Point of Service for billing and settlement purposes."

The Commission approved the amended wording.

Salt Box Coulee Water Supply Company Ltd. Ultraviolet Light System Upgrade Rate Rider (AUC Decision 24295-D01-2019)

Rate Rider

In this decision, the AUC considered and approved a request from Salt Box Coulee Water Supply Company Ltd. ("Salt Box") for a rate rider that would fund an ultraviolet light ("UV") system upgrade. The AUC approved a rate rider of $58 per customer per month.

Background

Salt Box was required to install a UV system under its approval from Alberta Environment and Parks ("AEP"). AEP had originally required such installation on or before December 1, 2011. Under a further approval, the UV system was required to be completed by December 1, 2019.

Salt Box had difficulty obtaining funds for the upgrade, and requested approval for a rate rider based on a $299,000 mortgage negotiated with Alpine Gas Ltd. ("Alpine"), which included a 12% interest rate over 10 years.

AUC findings

The AUC noted that its immediate concern was to ensure that customers would continue to receive a safe and adequate supply of water. It was apparent that Salt Box and its customers did not agree on the rates to be charged for water service. However, there was a significant and imminent risk that absent the completion of the UV system upgrade, the continuous supply of water to customers by Salt Box was likely to be impacted in the near future.

In setting a rate rider, the AUC noted that it gave consideration to the best available evidence and the submissions of parties on the amount of the rate rider.

The AUC noted that Salt Box provides service to 74 lots, and the rate rider over 10 years would amount to $58 per customer per month. It held that the term of the rider should match the term of the mortgage. It directed Salt Box to provide an annual reconciliation and to advise immediately of any changes to the terms of the financing.

The AUC advised that customers and Salt Box would have an opportunity to provide submissions in Proceeding 24295 on Salt Box's final rates, prior to closing the record of the proceeding. The UV system upgrades recovered in the rate rider approved in this decision would not be re-examined when setting final rates in Proceeding 24295.

CANADA ENERGY REGULATOR

Chevron Canada Limited Application for a 40 year Licence to Export Natural Gas as Liquified Natural Gas (Letter Decision)

Section 118 Surplus Criterion, Liquified natural gas

In this decision, the CER considered an application by Chevron Canada Limited ("Chevron") pursuant to section 117 of *the National Energy Board Act* ("*NEB Act*") for a 40-year licence to export natural gas in the form of liquified natural gas, with a maximum quantity of 982 109 m3 or 35 trillion cubic feet (Tcf) of natural gas over the term of the licence. The CER issued a 40-year License to Chevron Canada to export natural gas, subject to the approval of the governor in council ("GIC"), as well as a number of terms and conditions.

<u>Section 118 Surplus Criterion</u>

The key issue in the proceeding was the *NEB Act* section 118 Surplus Criterion. Chevron submitted that as required by the section 118 Surplus Criterion, the quantity of natural gas it sought to export did not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of gas in Canada. An intervenor argued that Chevron failed to meet its onus to provide evidence with respect to the section 118 Surplus Criterion.

<u>Views of the CER</u>

The CER accepted the expert evidence submitted by Chevron, noting that it was satisfied with the use of projections from the NEB publication *Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040* ("EF2016"). The CER agreed with Chevron's expert that, since those resource data were published, nothing has happened that would reduce confidence in the abundance of the resource. The CER also agreed that proved reserves account for a small fraction of the total resources. The intervenor's expert did not provide sufficient evidence to convince the CER otherwise.

The CER also noted that it did not agree with the intervenor expert's argument that broader North American gas resources are irrelevant to Canadian requirements. A project's connection to the North American gas market is an important factor when determining that the Surplus Criterion is met.

The CER also noted that it did not find cumulative licensed volumes to be an accurate or meaningful measure in assessing whether Canadians' requirements for natural gas will be met. Because of the fact that LNG ventures are competing for a limited global market, and face significant economic and financial challenges, the CER took the view, consistent with that of its predecessor the NEB, that not all LNG export licences issued will be used or used to their full allowance.

<u>Decision</u>

The CER approved Chevron's application for a 40-year licence to export natural gas in the form of liquified natural gas.

Abandonment Hearing NOVA Gas Transmission Limited 2018 Meter Stations and Laterals Abandonment Program (MHW-003-2019)

Pipeline Abandonment

In this decision, the CER considered an application by NOVA Gas Transmission Limited ("NGTL") for the abandonment of 15 meter stations and 22 associated lateral pipelines, one stand-alone meter station and four stand-alone laterals (the "2018 Program"). The CER granted NGTL leave to abandon these facilities (the "Facilities").

<u>Application and 2018 program overview</u>

The CER noted that the proposed 2018 Program was located throughout Alberta on freehold lands, lands owned by municipalities, Special Areas lands, Alberta Crown (Alberta Environment and Parks ["AEP"], and Alberta Tourism, Parks & Recreation) lands, Federal Crown (Canadian Forces Base ["CFB"] Suffield) lands, and on lands located on the Saddle Lake Cree Indian Reserve No. 125 ("SLC IR No.125").

NGTL stated that at each site the scope of its 2018 Program was relatively small in scale and short in duration with physical abandonment activities at each location lasting 14 to 28 days. Eleven facilities would be abandoned by removal including approximately 15 km of lateral pipelines. The remainder of the 2018 Program facilities, including approximately 158 km of lateral pipelines, would be abandoned in place. Above- and below-ground facility infrastructure would be removed at 16 meter station locations, and excavation and isolation would occur at 34 locations. All abandoned above-ground infrastructure (meter stations and side valves) would be removed.

Assessment of the Application

Engineering matters

The CER found that the 2018 Program's abandonment activities as described in the application were consistent with NGTL's commitment to conduct hazard assessments on the pipeline, and requirement to comply with CSA Z662-15 and the *National Energy Board Onshore Pipeline Regulations*. The CER was therefore satisfied with NGTL's approach.

Economics matters

The CER noted that the abandonment of the Facilities were not expected to have a material impact on service or tolls for NGTL's shippers. The CER was satisfied that NGTL has sufficient funds to carry out the abandonment work. The CER noted that NGTL's abandonment trust could be drawn upon in the case of unforeseen liabilities or reclamation obligations. The CER imposed a condition requiring quarterly physical abandonment activity cost reports.

Environment matters

The CER was of the view that the majority of potential adverse environmental effects arising from the 2018 Program would be of low magnitude, limited geographic extent, reversible in the short to medium term, and not likely to cause any significant adverse environmental effects.

Lands, public consultation and socio-economic matters

The CER was satisfied that anyone potentially affected by the 2018 Program was given sufficient notice and had the opportunity to voice their concerns. The CER was of the view that the design and implementation of consultation activities were appropriate for the scale and scope of the 2018 Program.

Indigenous matters

The CER reviewed NGTL's activities to engage Indigenous communities and learn about their concerns and interests. The CER was satisfied with the design and implementation of NGTL's consultation activities to date and was satisfied that any Indigenous community potentially affected by the 2018 Program was given notice and had the opportunity to voice their concerns both to NGTL and through the regulator's abandonment hearing process.

Decision

The CER granted NGTL leave to abandon the facilities.