REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA UTILITIES COMMISSION

Alberta Electric System Operator Compliance Filing and Report to Directions 13 and 14 from Decision 22942-D02-2019, AUC Decision 27015-D01-2021

Project Initiation - Project Need

On November 30, 2021, the Alberta Electric System Operator ("AESO") filed an application seeking approval of its compliance with directions 13 and 14 issued in Decision 22942-D02-2019.

In the relevant sections of Decision 22942-D02-2019 the AUC addressed concerns raised by EPCOR Distribution & Transmission Inc. that the classification of transmission project costs as between system-related and participant-related costs may be determined by whether the project has been initiated by the AESO or by the market participant. The classification influences the amount of any required construction contribution.

The AUC determined that it would be helpful if the AESO more clearly outlined the circumstances under which it would determine that a system need existed that required the AESO to initiate a system transmission project rather than requiring a distribution facility owner to make a system access service request. The AESO was directed to develop a set of criteria for the initiation of system transmission projects.

The AUC considered the consultative process undertaken by the AESO and found that the resulting application complied with the requirements of directions 13 and 14 from Decision 22942-D02-2019. The AESO's compliance with directions 13 and 14 was therefore approved.

AltaLink Management Ltd. Dunmore Solar Project, AUC Decision 27046-D01-2021

Facilities - Solar

In this decision, the AUC approved the applications from AltaLink Management Ltd. ("AML") for permission to construct and operate the Dunmore Solar Project Connection.

AUC Findings and Decision

AML applied to the AUC for approval to construct and operate a 138-kilovolt transmission line from the Dunmore 1011S substation (the "Substation") to an existing transmission line in the Medicine Hat area (the Dunmore Solar Project Connection). AML also applied to alter an existing transmission line to accommodate the connection and to connect the altered transmission line to the Substation.

The AUC determined that the applications filed by AML met the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines.*

The AUC was satisfied with the participant involvement program conducted by AML and was further satisfied with the environmental evaluation and by the environmental protection plan submitted with the applications.

The AUC consequently found that approval of the applications was in the public interest. The applications were approved pursuant to sections 14, 15, 18, and 19 of the *Hydro and Electric Energy Act*.

Apex Utilities Inc. 2022 Annual Performance-Based Regulation Rate Adjustment, AUC Decision 26851-D01-2021

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2022 annual performance-based regulation ("PBR") rate adjustment filing from Apex Utilities Inc. ("AUI"). The 2019 and 2020 rates that were previously approved on an interim basis were approved as final. The AUC approved 2022 distribution rate schedules, effective January 1, 2022, on an interim basis. AUI's special charges and terms and conditions of service ("T&Cs"), respectively, were also approved as filed, effective January 1, 2022, on a final basis.

Background

AUI submitted its 2022 annual PBR rate adjustment filing to the AUC, requesting approval of its 2022 gas distribution service rates, special charges, billing determinants, T&Cs and corresponding rate schedules, to be effective January 1, 2022, on an interim basis.

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X"). Apart from specifically approved adjustments, a utility's revenues are not linked to its costs during the PBR term.

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for some flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor"). However, in place of the capital tracker mechanism employed in previous-generation PBR plans, the AUC divided capital funding into two categories: Type 1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with narrow eligibility criteria, with the revenue requirement associated with any approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provided an amount of capital funding for each year of the next-generation PBR plan based, in part, on capital additions made during the previous PBR term.

AUI's 2021 PBR rates were approved on an interim basis in accordance with the PBR framework in Decision 25867-D01-2020.

PBR Rate Adjustments

2022 PBR Indices and Annual Adjustments

AUI's 2021 PBR plan provided a rate-setting mechanism based on a formula that adjusts revenue-per-customer annually, through an indexing mechanism plus specifically approved adjustments.

(a) I-X index

AUI calculated its 2022 I-X index to be 1.46 percent. The AUC approved the 2022 I factor of 1.76 percent and the resulting I-X index as calculated by AUI.

(b) Y and Z factor materiality threshold

AUI calculated the Y and Z materiality threshold to be $0.55 million for 2022. The AUC approved the Y and Z factor materiality threshold.

(c) Y factor and Z factor

AUI applied for a Y factor amount of $1.7 million inclusive of carrying costs. AUI did not apply for any Z factor adjustment in 2022. The AUC approved the Y factor as filed.

(d) Q Value

The AUC was satisfied with AUI's provided calculations and approved the 2022 Q value of 0.05 percent.

(e) K-bar factor and K factor

AUI applied for the 2022 K-bar funding of $14.13 million, calculated as its 2022 required K-bar funding of $14.57 million and 2020 K-bar true-up credit of $0.43 million.

K factor is used to recover the Type 1 capital funding that provides additional funding above that provided in base rates for projects that meet the specific criteria established. AUI did not apply for any K factor rate adjustments for 2022.

The AUC approved AUI's 2022 total K factor of $14.13 million. The 2022 K-bar is subject to a true-up for the 2022 actual approved cost of debt.

Forecast Billing Determinants and Variance Analysis

AUI provided detailed 2022 billing determinant forecasts. AUI submitted that its forecasted 2022 billing determinants were based on the same methodology approved in Decision 25867-D01-2020. The billing determinant forecast was approved, as applied for.

<u>2022 PBR Rates</u>

Distribution Rates and Rate Riders

The AUC approved AUI's 2022 PBR rates effective January 1, 2022, on an interim basis. The AUC found that the 2022 proposed rates are unlikely to result in rate shock to AUI's customers, who would experience bill impacts between 2.8 percent and 6.8 percent, excluding the commodity charge. Due to the rebasing process taking place in 2023, the AUC directed AUI to true-up the placeholders remaining in its 2022 distribution rates in a future proceeding to establish the 2023 rates, such as a compliance filing to the rebasing application.

AUI's special charges and standard contribution amounts set out in its 2022 special charges schedule were also approved.

<u>Other Matters</u>

Terms and Conditions of Service

AUI filed revisions to its T&Cs concerning the natural gas utility service rules and the retailer distribution service rules. The changes would reflect updates to business practices and provide clarity to customers. The AUC approved the changes.

Financial Reporting Requirements and Senior Officer Attestation

The AUC reviewed the financial information provided by AUI and was satisfied that it has complied with the financial reporting requirements set out in Decision 20414-D01-2016 (Errata).

Finalizing 2019 and 2020 Interim Rates

The AUC determined that all outstanding placeholders from 2019 and 2020 have been trued up, and there are no further outstanding matters relating to the calculation of the rates. The AUC approved AUI's request to finalize 2019 and 2020 interim rates.

***ATCO Electric Ltd. Approval of Amounts to be Paid into and Out of the Balancing Pool for the Sale of Isolated Generating Units*, AUC Decision 26953-D01-2021**
Isolated Generating Units - Net Book Value

In this decision, the AUC approved the application from ATCO Electric Ltd. ("AE") to pay a total amount of $1,674,560.60 to the Balancing Pool under Section 22(1) of the *Isolated Generating Units and Customer Choice Regulation*, following its sale of its isolated generating units at its Garden River Power Plant.

Introduction

AE, as a transmission facility owner, provides transmission service to isolated communities in Alberta using isolated generating units. When an isolated generating unit is no longer needed, AE may sell the isolated generating unit and must follow the process set out in Part 2 of the *Isolated Generating Units and Customer Choice Regulation*.

AE requested that the AUC approve payment in the amount of $2,409.40 to AE from the Balancing Pool in respect of selling costs; $15,000.00 from AE to the Balancing Pool for sale proceeds; and payment of $1,661,970.00 from AE to the Balancing Pool for the remaining net book value of the isolated generating units.

Analysis

The Balancing Pool raised a concern with what it asserted was AEs inclusion of $250,176.05 for dismantling costs in AE's net book value calculation. The Balancing Pool questioned if dismantling costs should be claimable in the current application as part of the isolated generating units' net book value.

The AUC found that the dismantling costs noted by the Balancing Pool do not affect the net book value calculation as these costs are offset entirely with what was previously collected by AE through its previous collections of net salvage, and therefore results in a net book value of zero. The AUC further found that AE's selling costs and sale proceeds were reasonable.

The AUC approved the total amount of $1,674,560.60 to be paid by AE to the Balancing Pool under Section 22(1) of the *Isolated Generating Units and Customer Choice Regulation*.

***ATCO Electric Ltd. 2022 Annual Performance-Based Regulation Rate Adjustment*, AUC Decision 26849-D01-2021**

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2022 annual performance-based regulation ("PBR") rate adjustment filing from ATCO Electric Ltd. ("AE"). The 2019 and 2020 rates that were previously both approved on an interim basis were approved as final. The AUC approved 2022 distribution rates, options and riders, and corresponding rate schedules on an interim basis. The AUC also approved the 2022 system access service ("SAS") rates as filed. The stand-alone schedules of Available Company Investment and Supplementary Service Charges were also approved.

The AUC further approved AE's proposed plan to collect the 2021 deferred amount associated with a deferral of its 2021 distribution rates increase and AE's 2020 annual transmission access charge deferral account ("TACDA") true-up as well as AE's 2020 Balancing Pool adjustment.

Background

AE requested approval of its 2022 electric distribution rates and transmission SAS rates, options and riders, and corresponding rate schedules, to be effective January 1, 2022, on an interim basis. AE additionally requested approval of its billing determinants and schedules of Available Company Investment and Supplementary Service Charges effective January 1, 2022. AE also included a request that its Balancing Pool Adjustment Rider B, 2020 annual TACDA true-up amounts be collected/refunded through Rider G and interim Rider J, effective January 1, 2022, in its application. AE's final request was approval of the calculation of its 2019 and 2020 going-in revenue and K-bar amounts on a final basis resulting in final rates for those years.

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for some flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (“Z factor”). However, in place of the capital tracker mechanism employed in previous-generation PBR plans, the AUC divided capital funding into two categories: Type 1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with narrow eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a “K factor” adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provided an amount of capital funding for each year of the next-generation PBR plan based, in part, on capital additions made during the previous PBR term.

AE’s 2021 PBR rates were approved on an interim basis in accordance with the PBR framework in Decision 25864-D01-2020. However, as a result of Decision 26170-D01-2020, AE’s 2021 distribution rates were maintained at the 2020 levels. In the current application, AE proposed to collect the majority of the amounts associated with the 2021 distribution rate increase deferral in 2022.

PBR Rate Adjustments

PBR Indices and Annual Adjustments

AE’s 2021 PBR plan provided a rate-setting mechanism based on a formula that adjusted rates annually through an indexing mechanism plus specifically approved adjustments.

(a) I-X index

AE calculated its 2022 I-X index to be 1.46 percent. The AUC reviewed AE’s calculation of the 2022 I factor and found it to be consistent with the methodology set out in Decision 20414-D01-2016 (Errata). Accordingly, the 2022 I factor of 1.76 per cent and the resulting I-X index of 1.46 per cent were approved.

(b) Y and Z factor materiality threshold

AE calculated the Y and Z materiality threshold to be $3.69 million for 2022. The AUC approved the Y and Z factor materiality threshold.

(c) Y factor and Z factor

AE applied for a Y factor amount of $7.741 million, and an additional carrying charge related to the deferral account and K-bar true-ups of $0.077 million to be refunded to customers. AE did not apply for any Z factor adjustments in 2022. The AUC approved the Y factor as filed.

(d) Q Value

The AUC was satisfied with AE’s provided calculations and approved the 2022 Q value of 0.414 percent.

(e) K-bar factor and K factor

AE applied for the 2022 K-bar funding of $75 million. AE’s 2020 and 2021 K-bar true-ups for the actual cost of debt resulted in refunds of $2.3 million for 2020 and $2.2 million for 2021. The AUC approved the applied-for K-bar funding, subject to a further true-up for the 2022 actual approved cost of debt, as well as the K-bar true-up refunds of $2.3 million for 2020 and $2.2 million for 2021.

AE did not apply for any K factor rate adjustments for 2022.

Forecast Billing Determinants and Variance Analysis

AE provided detailed 2022 billing determinant forecasts. AE submitted that its forecasted 2022 billing determinants were based on the same methodology approved in Decision 25864-D01-2020.

In Decision 25864-D01-2020, the Commission directed ATCO Electric to continue to provide information on any variances from forecast to actual billing determinants by rate class and identify the cause of variances larger than ± five per cent on an annual basis. There were variances larger than ± five per cent for the small general service, irrigation, rural electrification association ("REA") farm and irrigation, large general service, oilfield and street light rate classes in 2020. The AUC found that variances from forecasts such as those described by AE for 2020 may reasonably be expected for current purposes. Such occurrences do not generally call into question the predictive value of the methodology used to generate such forecasts and AE was directed to continue to provide information on any variances from forecast to actual billing determinants by rate class and to identify the cause of variances larger than ± five per cent on an annual basis.

The billing determinant forecast was approved, as applied for.

<u>2020 TACDA True-Up</u>

Total Net True-Up Amount

TACDA amounts are considered to be a part of the Y factor and are treated as a dollar-for-dollar flow-through of the Alberta Electric System Operator ("AESO") tariff charges.

AE's application and schedules were considered to be consistent with the harmonized framework approved in Decision 3334-D01-2015, and the AUC found the resulting amounts to be reasonable. The AUC approved a net refund of $1.720 million.

Rider G Rate and Effective Period

AE proposed to apply the 2020 annual TACDA true-up by way of a Rider G. To smooth rates over time and promote rate stability, AE proposed Rider G to be in effect over a 12-month period from January 1, 2022, to December 31, 2022. The AUC found AE's use of Rider G to collect the 2020 TACDA true-up amounts over a 12-month period to be reasonable because using a separate rider facilitates better tracking of these flow-through costs. The AUC approved Rider G as part of the 2022 PBR rates.

Inclusion of TACDA True-Up in the Annual PBR Rate Adjustment Filing

There will be no annual PBR rate adjustment filings in 2022 and 2023 due to the rebasing process taking place between the current and the next PBR term. The annual TACDA true-up applications for 2021 and 2022 may therefore be filed under stand-alone proceedings until annual PBR rate adjustment filings resume in the next PBR term. Under this approach, the AUC directed AE to file its 2021 and 2022 annual TACDA true-up applications by September 10 of 2022 and 2023, respectively.

<u>2022 PBR Rates</u>

System Access Service Rates

AE indicated that its proposed 2022 SAS rates reflected the rates approved in the AESO 2021 Independent System Operator tariff, approved in Decision 26054-D01-2020. The SAS payments forecast for distribution-connected customers increased from $356.8 million, included in 2021 PBR rates, to $383.4 million for 2022. This increase in forecast SAS payments reflects an increase of 7.44 per cent in the transmission SAS rate. The AUC reviewed AE's calculations of the proposed 2022 SAS rates and the underlying assumptions and found them to be reasonable. The AUC approved the proposed 2022 SAS rates.

Distribution Rates: 2022 PBR Rates Including 2021 Deferred Amount (Rider J)

AE's 2022 rates bill impact schedules reflected impacts of 10 percent or more for several rate classes. These bill impacts are at or near the AUC's rate shock threshold. The bill impacts arise from the 2022 rates considered in this decision as well as AUC approvals and directions in decisions 26170-D01-2020 and 26360-D01-2021 relating to the 2021 deferred amount.

To keep bill impacts below 10 percent, AE proposed to collect $42.1 million in 2022, while the remaining balance of $21.8 million would be recovered in 2023. The remaining balance carried forward into 2023 would only apply to rate classes experiencing a bill impact of at least 10 percent. AE indicated it would true-up any differences in collected revenue arising from the difference between forecast and actual billing determinants in future applications.

The AUC evaluated this scenario and other possibilities and found that AE's proposed approach ultimately minimizes the overall costs to ratepayers and in the case of AE's proposed implementation of Rider J specifically, minimizes intergenerational inequity. AE's 2022 PBR rates, including the use of an interim Rider J, were approved on an interim basis.

Rider E – Facilities Charge Agreements

AE removed Rider E from its price schedules effective January 2021 because Rider E no longer forms part of AE's regulated service offering. AE confirmed that, as directed by the AUC, all contractual amendments required to remove the remaining customer services from regulated service under Rider E would be executed by December 31, 2021.

<u>Other Matters</u>

Distribution-Connected Generation Credit – Rate D32

Distribution-connected generation ("DCG") credits are the payments that AE, among others, provides to DCG connected to its distribution systems. These credits are calculated and paid pursuant to provisions within AE's tariff. In AE's distribution tariff, this credit is defined in the price schedule for Rate D32. This cost is recovered from ratepayers as part of SAS costs.

In Decision 26090-D01-2021, the AUC determined that the AESO rate demand transmission service ("DTS") portions of the DCG credit mechanism are to be diminished over a four-year transition period until they are discontinued in 2026. AE was directed to calculate the DTS portion of Rate D32 in the same way that it otherwise would have, but then reduce the value of the DTS portion of the DCG credit by applying a multiplier to it before finalizing and issuing the credit.

AE added the prescribed multipliers into its rate schedules but did not account for the effects of the multipliers on its transmission access cost forecast, and the SAS cost forecast assumed that DCG credits were paid as if the multiplier did not exist.

AE proposed to forecast its SAS billing determinants in a consistent manner at this point and consider making adjustments to its forecast beginning in 2023, once the multiplier is at a lower percentage. The AUC accepted AE's proposed approach.

Terms and Conditions of Service and Other Rate Schedules

AE adjusted its maximum investment levels and supplementary service charges schedules by the 2022 I-X index. The AUC found that these changes were consistent with Decision 20414-D01-2016 (Errata) and approved them. AE did not apply for changes to its terms and conditions

Financial Reporting Requirements and Senior Officer Attestation

The AUC determined that AE had complied with all financial reporting requirements.

Finalizing 2019 and 2020 Interim Rates

The AUC approved AE's 2019 and 2020 rates on a final basis because all outstanding K factor and Y factor adjustments have been trued up, and no outstanding matters remained.

***ATCO Gas and Pipelines Ltd. 2022 Annual Performance-Based Regulation Rate Adjustment*, AUC Decision 26847-D01-2021**

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2022 annual performance-based regulation ("PBR") rate adjustment filing from ATCO Gas and Pipelines Ltd. ("AGP"). The AUC approved AGP's 2019 and 2020 interim rates on a final basis and approved the 2022 distribution rates for ATCO Gas North and ATCO Gas South and the schedule of non-discretionary charges on an interim basis. The AUC also approved the calculation of AGP's prior year depreciation adjustment Rider S recovery and the recovery of the 2021 deferred amount associated with a deferral of the 2021 distribution rates increase.

Background

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor"). However, in place of the capital tracker mechanism employed in previous-generation PBR plans, the AUC divided capital funding into two categories: Type 1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with narrow eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provided an amount of capital funding for each year of the next-generation PBR plan based, in part, on capital additions made during the previous PBR term.

PBR Rate Adjustments

PBR Indices and Annual Adjustments

AGP's 2021 PBR plan provided a rate-setting mechanism based on a formula that adjusts revenue-per-customer annually through an indexing mechanism plus specifically approved adjustments.

(a) I-X index

AGP calculated its 2022 I-X index to be 1.46 percent. The AUC review AGP's calculations and approved the 2022 I factor of 1.76 percent, resulting in the 2022 I-X index as calculated by AGP.

(b) Y and Z factor materiality threshold

AGP calculated the Y and Z materiality threshold to be $2.13 million for 2022. The AUC approved the Y and Z factor materiality threshold as applied for.

(c) Y factor and Z factor

AGP applied for a Y factor amount of $3.6 million inclusive of carrying costs. AGP did not apply for any Z factor adjustment in 2022. The AUC approved the Y factor as filed.

(d) Q Value

The AUC was satisfied with AGP's calculations and approved the 2022 Q value of 1.52 percent for ATCO Gas North and 1.62 percent for ATCO Gas South as applied for.

(e) K-bar factor and K factor

AGP applied for 2022 K-bar funding of $36.1 million and $34.5 million for ATCO Gas North and South, respectively. The AUC approved the 2022 K-bar funding and noted that it will be subject to a further true-up for the 2022 actual approved cost of debt. The AUC also approved AGP's 2020 K-bar true-up refunds of $2.7 million and $2.3 million for ATCO Gas North and South, respectively, as well as the 2021 K-bar true-up refunds of $2.8 million and $2.4 million for ATCO Gas North and South, respectively.

AGP did not apply for any K factor rate adjustments for 2022.

Forecast Billing Determinants and Variance Analysis

AGP provided detailed 2022 billing determinant forecasts. AGP submitted that its forecasted 2022 billing determinants were based on the same methodology approved in Decision 25867-D01-2020. The billing determinant forecast was approved, as applied for.

<u>2022 PBR Rates</u>

Distribution Rates: 2022 PBR Rates Including 2021 Deferred Amount and Rider S

The AUC approved AGP's calculations of the 2022 PBR rates. The AUC also approved AGP's proposal to recover the 2021 deferred amount. Although the resulting bill impacts are elevated, the AUC found that AGP ensured that costs to ratepayers would be minimized. AGP's 2022 PBR rates were approved on an interim basis, effective January 1, 2022.

Recovery of the 2021 Deferred Amount

AGP's most recent annual rate filing was approved in Decision 25863-D01-2020 dealing with 2021 PBR rates. However, while that decision approved the calculation of AGP's 2021 PBR distribution rates in accordance with the PBR framework, those rates were not charged to customers effective January 1, 2021. Rather, as a result of Decision 26170-D01-2020, AGP's distribution rates were maintained at the 2020 levels. In the current application, AGP proposed to collect in 2022 the amounts associated with the 2021 distribution rate increase deferral.

AGP applied for approval to collect the entire amount deferred in 2021, following approvals as part of its 2022 PBR rates.

The AUC has reviewed AGP's calculations for the proposed Rider S and the 2022 recovery of the 2021 deferred amount and was satisfied that AGP's proposal was reasonable and that AGP's calculations were reasonable as well. AGP's calculation of its 2022 PBR rates, inclusive of the January 1 to June 30, 2022, Rider S and the recovery of the 2021 deferred amount, was approved.

<u>Other Matters</u>

AGP did not apply for changes to its terms and conditions of service ("T&Cs"). AGP's customer for gas distribution service and retailer T&Cs for gas distribution service approved in Decision 26283-D01-202130 remain in effect.

The AUC was satisfied that AGP had complied with the financial reporting requirements and the AUC approved AGP's 2019 and 2020 rates on a final basis.

***ATCO Gas, a Division of ATCO Gas and Pipelines Ltd. 2022 Transmission Service Charge (Rider T)*, AUC Decision 26952-D01-2021**

Rates - Gas

In this decision, the AUC approved the 2022 transmission service charge rider (Rider T) rates for ATCO Gas, a division of ATCO Gas and Pipelines.

Background

ATCO Gas flows the rates charged by the transmission service provider, NOVA Gas Transmission Ltd. ("NGTL") through to its customers through Rider T. Rider T is the service charge used to collect forecast transmission costs and to refund or collect any differences between the prior year's forecast and actual costs.

NGTL filed its proposed 2022 interim rates and abandonment surcharge for the Alberta system with the CER. NGTL's proposed 2022 interim rates and abandonment surcharge included changes that would impact ATCO Gas' transmission service charge. ATCO Gas requested approval for new Rider T rates to account for changes in the proposed NGTL interim rates.

Discussion of Issues

Timing of Application

ATCO Gas did not file the 2021 Rider T application in the typical timeframe of January and instead filed the application on March, 2021, with a May 1, 2021, effective date. The application was filed later than usual to consider the Rider T application related to its 2021 interim rate relief request and corresponding 2021 PBR rate implementation application.

In this application, ATCO Gas implemented its revised rate design as part of the 2022 annual PBR rate adjustment filing (Proceeding 26847). Although it originally planned to update the January 1, 2022 Rider T rate calculations for all rate groups as part of its 2022 annual PBR rate adjustment filing, ATCO Gas proposed to defer the Rider T calculations until NGTL files the rate change request with the CER. This would allow better alignment of rates.

The AUC agreed that the proposed timing allows for better alignment of rates for January 1, 2022, and agreed that using this timing for future Rider T applications will also result in better alignment with future rate change requests filed by NGTL.

Cross-Subsidization Between North and South Customers

A province-wide Rider T rate is applied to ATCO Gas' north and south territories. Cross-subsidization issues between ATCO Gas's north and south service territories were considered in Decision 2014-062.

ATCO Gas was previously directed to provide details on the contributing factors of cross-subsidization if a Rider T application showed the subsidy between residential customers exceeded the $4.16 annual amount. In this application, ATCO Gas noted that this amount was not exceeded. As the AUC found the cross-subsidization amounts to be minimal, it accepted the continued use of province-wide Rider T rates.

Rider T Rates and Bill Impacts

ATCO Gas explained that assuming an implementation date of January 1, 2022, in isolation of any other rate changes, the total annual charges for a residential customer in the north and in the south service territory would decrease by approximately 0.5 percent. These rate changes, when combined with ATCO Gas' proposed 2022 PBR rates in Proceeding 26847, would result in the total annual charge for the same customer in the north and in the south service territory to increase by a similar amount.

When considered together with rate changes applied for in Proceeding 26847, the AUC determined that the effect of the proposed Rider T rates is unlikely to result in rate shock. Therefore, and given the flow-through nature of Rider T charges, the AUC found the rate impact to be reasonable for all rate classes.

AUC Decision

The AUC approved the Rider T rates, effective January 1, 2022, as applied for. The rates are:

- Alternative Technology and Appliance delivery service customers: $1.074 per gigajoule (“GJ”);
- low-use customers: $1.074 per GJ;
- mid-use customers: $1.030 per GJ;
- high-use customers: $0.281 per day of GJ demand; and
- ultra-high-use customers: $0.290 per day of GJ demand.

***Canadian Utilities Limited Application for the Amalgamation of ATCO Energy Solutions Ltd. and ATCO Alberta Storage Hub Ltd.*, AUC Decision 27034-D01-2021**

Amalgamation - Non-Regulated Entities

In this decision, the AUC approved the application from Canadian Utilities limited (“CU”) for the amalgamation of ATCO Energy Solutions Ltd. (“AES”) and ATCO Alberta Storage Hub Ltd. (“ATCO Hub”) (the “Amalgamation”). The application was approved under Section 101(2)(d)(ii) of the *Public Utilities Act* (“PUA”) and Section 26(2)(d)(ii) of the *Gas Utilities Act* (“*GUA*”) because the AUC’s no-harm test was satisfied.

Should the AUC Approve the Amalgamation of ATCO Energy Solutions Ltd. and ATCO Alberta Storage Hub Ltd. Into AES Amalco?

CU stated that AES and ATCO Hub will amalgamate into and continue as the corporation, ATCO Energy Solutions Ltd. (“AES Amalco”). AES is an unregulated, wholly owned subsidiary of CU. CU indicated that the amalgamation will not adversely affect any member of the public who is receiving service from the regulated ATCO utilities. The amalgamation would not result in any impact to utility service, would not increase the utility rates, impact gas or public utility service, or the regulatory oversight of CU.

The proposed amalgamation is a merger or consolidation of property outside the ordinary course of business and accordingly requires the consent of the AUC pursuant to Section 101(2)(d) of the *PUA* and Section 26(2)(d) of the *GUA*. The central question determining AUC approval is whether customers are harmed by the amalgamation. To assess this, the AUC applied its three-part no-harm test.

The amalgamation concerns two existing non-regulated entities. As a result, the AUC found that the amalgamation is not expected to impact customers negatively, and therefore, customers will be no worse off after the amalgamation is completed. The AUC also found that the amalgamation does not have potentially harmful operational effects on customers that may impair the integrity and reliability of the systems operated by the regulated ATCO utilities. The approval of CU’s application for the amalgamation will therefore not result in any financial harm to customers.

The AUC determined that the requirements of the no-harm test were satisfied and approved the amalgamation as filed.

***ENMAX Energy Corporation 2022 Non-Energy Regulated Rate Option Interim Tariff*, AUC Decision 27043-D01-2021**

Rates

In this decision, the AUC approved the 2022 interim administration charges and revised 2022 rate schedules applied for by ENMAX Energy Corporation ("EEC") on an interim basis, effective January 1, 2022. The AUC also approved a continuation of the existing terms and conditions of service.

The approved interim administration charges are a continuation of EEC's existing rates of $0.2201 per day for residential customers and $0.1975 per day for commercial customers.

Details of the Application and AUC Findings

EEC requested a continuation of the approved EEC 2021 regulated rate tariff non-energy charges. The requested 2022 interim administration charges would be on an interim refundable basis.

The AUC found the proposal reasonable and efficient. With the continuation, there would be no possible rate shock, and the future regulatory burden in setting 2022 final non-energy rates would be reduced.

EEC also applied for approval of minor wording changes to its 2022 rate schedules. The AUC found that the proposed changes do not affect the substance of the terms and conditions of service and improve the readability of the schedules.

The revised 2022 rate schedules were approved, effective January 1, 2022, on an interim basis until the final 2022 rate schedules are approved.

***ENMAX Power Corporation 2022 Annual Performance-Based Regulation Rate Adjustment*, Decision 26844-D01-2021**

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2022 annual performance-based regulation ("PBR") rate adjustment filing from ENMAX Power Corporation ("EPC"). The AUC approved the updates to EPC's distribution tariff terms and conditions ("T&Cs"). EPC's request to recover or refund the transmission access charge deferral account ("TACDA") amounts related to the historical errors for 2015 through 2019 was denied. The 2020 TACDA true-up and associated TAC Rider was approved subject to providing the clean version of supporting schedules showing the removal of the TACDA amounts related to the historical errors for years 2015 through 2019. The AUC also denied the Type 1 capital placeholder for 2022 K factor adjustments.

Background

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor"). However, in place of the capital tracker mechanism employed in previous-generation PBR plans, the AUC divided capital funding into two categories: Type 1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with narrow eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provided an amount of capital funding for each year of the next-generation PBR plan based, in part, on capital additions made during the previous PBR term.

EPC's most recent annual rate filing dealing with 2021 PBR rates was approved on an interim basis in Decision 25865-D01-2020. The present application is the last annual PBR rate adjustment filing in the current 2018-2022 PBR term. In 2023, rates will be established based on a cost-of-service review of the distribution utilities' forecast costs. This review will also serve as rebasing for the next PBR term for Alberta distribution utilities that will commence in 2024.

<u>PBR Rate Adjustments</u>

PBR Indices and Annual Adjustments

The 2021 PBR plan for EPC provided a rate-setting mechanism based on a formula that adjusted rates annually through an indexing mechanism plus specifically approved adjustments.

(a) I-X index

EPC calculated its 2022 I-X index to be 1.46 percent. The AUC approved the 2022 I factor of 1.76 percent and the resulting I-X index as calculated by EPC.

(b) Y and Z factor materiality threshold

EPC calculated the Y and Z materiality threshold to be $1.94 million for 2022. The AUC approved the Y and Z factor materiality threshold as applied for.

(c) Y factor and Z factor

EPC applied for a Y factor amount of $1.86 million inclusive of carrying costs. EPC did not apply for any Z factor adjustment in 2022. The AUC approved the Y factor as filed.

(d) Q Value

The AUC was satisfied with EPC's calculations and approved the 2022 Q value of 1.47 percent.

(e) K-bar factor and K factor

EPC applied for 2022 K-bar funding of $35.70 million, K-bar true-ups from 2020 and 2021 and associated carrying charges. ENMAX calculated its 2020 K-bar true-up as -$0.96 million and the 2021 K-bar true-up of -$1.01 million and associated carrying costs totaled -$0.06 million. No party objected to ENMAX's applied-for K-bar funding.

The AUC approved the net 2022 K-bar Funding of $33.67 million, including true-ups and carrying charges subject to a true-up for the 2022 actual approved cost of debt.

The K factor is used to recover the Type 1 capital funding that provides additional funding above that provided in base rates for projects that meet the specific criteria established by the AUC. Projects in this category can be approved on a placeholder basis. EPC has three Type 1 capital placeholders for the cost recovery of 90 percent of the management-approved internal 2019, 2020, and 2021 forecasts associated with the relocation of EPC's infrastructure following the City of Calgary's Green Line Light Rail Transit ("LRT") Project. The corresponding approved revenue requirement figures were $1.02 million for 2019, $1.25 million for 2020, and $1.78 million for 2021.

In this proceeding, EPC requested approval of a Type 1 capital placeholder for the amount of $2.0 million, associated with the Green Line LRT Project. However, as the AUC determined in Decision 26589-D01-2021 that the Green Line LRT Project does not qualify for Type 1 capital tracker treatment, the request for Type 1 capital placeholder in this proceeding was denied.

Forecast Billing Determinants and Variance Analysis

In Decision 23355-D01-2020, EPC was directed to provide an analysis of its 2020 forecast billing determinant with actual 2020 billing determinants with a variance of five percent or more. EPC submitted that all classes but the residential rate class, experienced a variance of negative five percent due to diminished demand caused by the COVID-19 pandemic. The residential rate class experienced a positive variance, also due to the COVID-19 pandemic.

The AUC determined that these variances from forecasts can be reasonably expected and do not generally call the predictive value of the methodology used to generate the forecasts into question. The AUC found that the methodology employed and the resulting 2022 forecast billing determinants were reasonable.

TACDA True-up

In the current PBR plan, TACDA amounts are considered to be a part of the Y factor and are treated as a dollar-for-dollar flow-through of the Alberta Electric System Operator ("AESO") tariff charges.

Treatment of Identified TACDA Errors

In the original application for this proceeding, EPC identified an issue with the calculation of its TACDA balances and riders. EPC had misinterpreted the TACDA schedules template, which led to a form of double counting. EPC submitted later that the errors affect its TACDA balances and TAC riders stretching back to 2015. EPC indicated that its errors caused it to under-recover in some years and to over-recover in others. As a result of the error, EPC sought approval for a net collection of $10.27 million associated with the revised historical TACDA amounts for the period 2015 to 2019.

The AUC noted that generally, ratemaking must be prospective. Past financial results can only be used to forecast future expenses. The AUC noted that deferral accounts are one of the established exceptions to prohibited retroactive or retrospective ratemaking.

The AUC took issue with the time it took EPC to identify the issue and its cause. While EPC stated it had adequate internal control review processes and supervisory systems in place, it took nearly six years to identify the misinterpretation and related impacts on annual TACDA true-up amounts. The AUC also agreed with an argument made by the Consumers' Coalition of Alberta that noted that there appeared to be a lapse in accounting oversight in addition to the calculation errors.

The AUC had previously stipulated that it approved flow-through treatment for AESO-related costs because the utility cannot control them. In this case, the error was mathematical and made in comparing the forecast to actual costs. The accuracy of such a comparison is entirely within the control of EPC. Therefore, the SAS deferral true-up should not include the utility's calculation errors. The AUC determined that the request to recover the TACDA amounts related to the historical errors for years 2015 through 2019 is not strictly prohibited as retroactive ratemaking but is an unacceptable use of the TACDA. The request was denied.

2020 TACDA True-Up

The AUC determined that the 2020 TACDA schedules are consistent with the harmonized framework previously approved by the AUC. The AUC found the amounts comprising the 2020 annual TACDA true-up, without the amounts related to the historical errors for years 2015 through 2019, to be reasonable. The AUC approved a net refund of $0.92 million and corresponding rider rates, contingent on EPC providing a clean version of its 2020 TACDA schedules and 2022 PBR rates schedules in a compliance filing to this decision.

PBR Rates

Distribution Rates

EPC was directed to remove the TACDA amounts related to the errors for years 2015 through 2019 from the 2020 TACDA true-up and the applied-for placeholder for the Green Line LRT Project. EPC was also directed to update its Balancing Pool Rider to reflect the currently approved AESO Rider F. As a result, while the AUC was satisfied with the rate calculation method, EPC's 2022 PBR rate calculations needed to be revised.

EPC was directed to file a compliance filing to this decision by December 10, 2021, consistent with the directions provided in this decision, including a revision of the rate calculations.

DAS Adjustment Rider

EPC proposed a distribution access service ("DAS") true-up Rider of $0.10 million, effective January 1, 2022, to March 31, 2022. The AUC determined that the proposed DAS Rider adjustment is consistent with EPC's historical practice approved by the AUC and therefore approved the adjustment for 2022.

Balancing Pool Adjustment Rider

EPC's application did not include an update needed following the AUC's approval of the Alberta Electric System Operator's ("AESO") 2022 Rider F charge. As a result, EPC was directed to update its application to include the approved 2022 Rider F in a compliance filing.

Other Matters

AESO Contributions Hybrid Deferral Account

Changes to historical AESO contribution amounts made by EPC are captured in a deferral account and subject to true-up. Further, incremental capital funding for new AESO contributions is provided through the K-bar.

EPC applied for capital additions to the rate base of $0.03 million in 2020 and $0.10 million in 2021. EPC also applied for a true-up of 2020 hybrid deferral account amounts collected in 2021, as the cost of debt for 2020 was available at the time of this application. This resulted in a 2020 deferral account true-up refund of $0.08 million, and a 2021 deferral account true-up refund of $0.49 million. The total adjustment for the AESO contribution hybrid deferral account is a refund of $0.59 million, including associated carrying costs. The AUC approved this adjustment refund.

Terms and Conditions of Service

EPC proposed a modification to its customer T&Cs to allow all retailers, in addition to the default supplier and regulated rate provider, to request EPC to de-energize and re-energize a customer site. Further, retailer T&Cs were amended to allow all retailers to request EPC to de-energize and re-energize a customer site. The AUC found these amendments reasonable and approved them.

Financial Reporting

The AUC reviewed the financial information provided by EPC and was satisfied that EPC complied with the financial reporting requirements.

***ENMAX Power Corporation Compliance Filing to Decision 26589-D01-2021 and Decision 26844-D01-2021*, AUC Decision 27042-D01-2021**

PBR – Compliance Filing

In this decision, the AUC determined that ENMAX Power Corporation ("EPC") had complied with all directions issued by the AUC in Decision 26589-D01-2021 and Decision 26844-D01-2021, relevant to this compliance filing.

Compliance with AUC Directions

In Decision 26589-D01-2021, the AUC denied EPC's request for Type 1 capital tracker treatment of the Green Line Light Rail Transit ("LRT") Project and required a compliance filing to refund all associated placeholder amounts collected from customers.

EPC complied with the direction in this compliance filing and calculated a 2019-2021 Type 1 capital true-up refund of $4,055,739 plus associated carrying costs of $158,666 to be refunded to customers in 2022.

Further, as directed, EPC provided a clean version of its 2020 TACDA schedules showing the removal of the transmission access charge deferral account ("TACDA") amounts related to the historical errors for years 2015 through 2019. The resulting 2020 TACDA true-up amounts and associated rider rates were the same as conditionally approved in Decision 26844-D01-2021.

Finally, as directed, EPC updated its Balancing Pool allocation Rider to reflect the approved Alberta Electric System Operator Rider F in its 2022 PBR rates.

Resulting 2022 PBR Rates

EPC provided the updated set of its 2022 distribution tariff rate schedules to reflect the impact of compliance with the AUC's directions. The AUC considered the practices and methodologies EPC employed for its calculations as well as the typical bill impacts expected. The AUC found that there is no expected rate shock. The AUC found no remaining issues and approved the 2022 PBR rates on an interim basis, effective January 1, 2022.

***EPCOR Distribution & Transmission Inc. 2022 Annual Performance-Based Regulation Rate Adjustment*, AUC Decision 26852-D01-2021**

***Rates - Performance-Based* Regulation**

In this decision, the AUC considered the 2022 annual performance-based regulation ("PBR") rate adjustment filing from EPCOR Distribution & Transmission Inc. ("EPCOR"). The AUC approved 2022 distribution rates, options and riders, and corresponding rate schedules on an interim basis. The 2022 system access service ("SAS") rates were approved as filed. The AUC also approved the distribution connection service ("DCS") terms and conditions ("T&Cs") and EPCOR's T&Cs for electric distribution access service ("DAS") and 2022 distribution tariff policies, on a final basis. The AUC also approved a Rider J for the recovery of amounts under the 2020 transmission access charge deferral account ("TACDA").

Background

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor"). However, in place of the capital tracker mechanism employed in previous-generation PBR plans, the AUC divided capital funding into two categories: Type

1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with narrow eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provided an amount of capital funding for each year of the next-generation PBR plan based, in part, on capital additions made during the previous PBR term.

EPCOR's 2021 PBR rates were approved on an interim basis in accordance with the PBR framework in Decision 25862-D01-2020.

PBR Rate Adjustments

PBR Indices and Annual Adjustments

EPCOR's 2021 PBR plan provided a rate-setting mechanism based on a formula that adjusted customer rates annually through an indexing mechanism plus specifically approved adjustments.

(a) I-X index

EPCOR calculated its 2022 I-X index to be 1.46 percent. The AUC approved the 2022 I factor of 1.76 percent and the resulting I-X index as calculated by EPCOR.

(b) Y and Z factor materiality threshold

EPCOR calculated the Y and Z materiality threshold to be $1.82 million for 2022. The AUC approved the Y and Z factor materiality threshold as filed.

(c) Y factor and Z factor

EPCOR applied for a Y factor amount of $12.61 million, inclusive of carrying costs. The AUC approved the Y factor as filed. During the course of the proceeding, amounts were changed. This included the Alberta Electric System Operator ("AESO") customer contributions. The AUC however held that the change in regulatory accounting treatment of new AESO customer contributions would be reflected in distribution facility owner ("DFO") rates as part of the upcoming DFO cost-of-service rebasing process for 2023. As a result, the AUC approved the originally applied for Y factor of $12.61 million. EPCOR did not apply for any Z factor adjustments to be included in its 2022 PBR rates.

(d) Q Value

The AUC was satisfied with EPCOR's calculations and approved the 2022 Q value of 0.12 percent, as filed.

(e) K-bar factor and K factor

EPCOR applied for 2022 K-bar funding of $35.1 million. The AUC found that the calculation of the 2022 K-bar amount followed the methodology set out in Decision 22394-D01-2018. The AUC noted that the 2022 K-bar amount is subject to a further true-up for the 2022 actual approved cost of debt.

EPCOR did not apply for K factor rate adjustments for 2022.

Forecast Billing Determinants and Prior Year Variance Analysis

EPCOR indicated that its 2021 billing determinants forecast was based on the methodology approved in Decision 25866-D01-2020 and throughout the PBR regime, except for the Direct Connect ("DC"), Customer Specific ("CS") and Customer Specific Totalized ("CST") rate classes. To forecast its 2022 DC, CS, and CST customer rate classes, EPCOR used a three-year average of energy and demand. It based its forecast on a three-year model to even out deviations in a given year.

The AUC was of the view that variances from forecasts noted by EPCOR for 2020 may reasonably be expected for current purposes. The AUC however noted that the DC and CST rate class energy variances continue to be the most significant of the variances at -13.5 percent and -35.27 percent respectively, and may require increased scrutiny in future annual rate update applications.

The AUC found EPCOR's methodology and billing determinants to have been reasonable and approved the three-year average methodology in calculating the 2022 rates for the DC and the CST rate classes and the resulting 2022 forecast billing determinants, as filed.

True-Ups for 2022

The AUC found EPCOR's calculations and explanations of the 2020 true-ups to be reasonable. The AUC approved the inclusion of the $5.84 million true-up refund amounts in EPCOR's 2022 PBR rates.

2020 TACDA True-Up

Total Net True-Up Amount

TACDA amounts are considered to be a part of the Y factor and are treated as a dollar-for-dollar flow-through of the AESO tariff charges. Annual TACDA true-up schedules are based on the harmonized framework approved by the AUC for distribution utilities in Decision 3334-D01-2015.

The AUC considered EPCOR's application and schedules consistent with the harmonized framework approved in Decision 3334-D01-2015, and the AUC found the resulting amounts to be reasonable. The AUC approved a net refund of $0.06 million

Rider J Rate and Effective Period

EPCOR proposed to apply the 2020 annual TACDA true-up by way of a Rider J. The AUC found EPCOR's use of Rider J to collect the 2020 TACDA true-up amounts to be reasonable because using a separate rider facilitates better tracking of these flow-through costs. The AUC approved Rider J as part of the 2022 PBR rates.

2022 PBR Rates

System Access Service Rates

EPCOR indicated that its proposed 2022 SAS rates reflect the rates approved in the AESO 2021 Independent System Operator tariff, approved in Decision 26054-D01-2020. EPCOR's calculations of the proposed 2022 SAS rates, the underlying assumptions, and 2022 Balancing Pool Rider G were found to be reasonable and consistent with its past SAS rate applications. The AUC approved the proposed 2022 SAS rates and 2022 Balancing Pool Rider G.

Customer Specific Rates

EPCOR did not apply for any new proposed CS customer rates. Contrary to AUC directions, EPCOR did not include the true-up of the CS42 rate to reflect the 2020 actual weighted average cost of capital ("WACC") rate in this application. EPCOR showed that the 2020 WACC rate true-up required a refund of $38,049.26 to the customer, translating to a daily rate refund of $104.24. A per-day adjustment to the CS42 rate was determined as an acceptable method of implementing the 2020 WACC true-up. The daily refund of $104.24 to the CS42 customer was approved.

Distribution Rates

The AUC approved EPCOR's 2022 PBR rates effective January 1, 2022, on an interim basis until the approved levels of all remaining placeholders have been determined by the AUC. These 2022 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.

Terms and Conditions of Service

The AUC approves EPCOR's customer DCS T&Cs and retailer DAS T&Cs including amendments in accordance with the I-X mechanism proposed by EPCOR. EPCOR adjusted its maximum investment levels ("MILs") and specific customer contributions by the I-X for 2021 in its customer DCS T&Cs.

Financial Reporting Requirements and Senior Officer Attestation

The AUC reviewed the financial information provided by EPCOR and was satisfied that it has complied with the financial reporting requirements.

***EQUS REA Ltd. Complaint Application for Relief and Orders Concerning the Transfer of Consumers to EQUS from FortisAlberta Inc.*, AUC Decision 26668-D01-2021**
Transfer of Service - Exit Charge

In this decision, the AUC determined that FortisAlberta Inc. ("FortisAB") may levy exit charges, as defined in Section 7.5 of its terms and conditions of service ("T&Cs"), on one of its existing consumers (the "Consumer") in connection with a request to transfer its electric distribution service from FortisAB to EQUS REA Ltd. ("EQUS"). The AUC determined that FortisAB may levy the charges when it transfers its service to EQUS; however, FortisAB must use the amount it receives from EQUS for the transferred facilities as the value of the salvaged facilities for the purposes of calculating the exit charges.

Background

In rural Alberta, electric distribution service is generally provided by two public distribution utilities, FortisAB and ATCO Electric Ltd., or by a rural electrification association ("REA"). The geographic service areas of the public distribution utilities and the REAs overlap. A person receiving electric distribution service from FortisAB or EQUS has the ability to change their electric distribution service provider such that they may become a member of EQUS or a customer of FortisAB. As part of such a change, facilities required to serve the customer can be transferred between FortisAB and EQUS pursuant to the provisions of an integrated operation agreement ("IOA").

Application

EQUS complained that FortisAB had levied exit charges on Jayson Schwab and 2033698 Alberta Ltd., operating as Sunny Beah R.V. Resort, in response to requests to transfer electric distribution service to EQUS. EQUS sought the following orders and relief:

(i) A declaration that the Distribution Customer Exit Charges proposed to be levied by FortisAB against J. Schwab and the Sunny Beach R.V. Resort do not apply and are not lawful, valid or applicable.

(ii) A declaration that all T&Cs applying to the transfer to EQUS of J. Schwab's and the Sunny Beach R.V. Resort's services and FortisAB's distribution assets to respectively serve them are governed exclusively by the IOA.

As the Sunny Beach R.V. Resort abandoned its transfer request, the AUC limited its determinations to the request of J. Schwab.

Discussion of Issues

As a preliminary matter, the AUC noted three transactions are required for a Consumer to cease receiving electric distribution service from FortisAB and to start receiving it from EQUS: (1) the Consumer would discontinue receiving electric distribution service from FortisAB and disconnect from FortisAB's distribution system; (2) FortisAB would transfer facilities to EQUS pursuant to the provisions in the IOA, and the Consumer's request to have its facilities transferred; and (3) the Consumer would enroll as a member of EQUS and connect to EQUS's distribution system.

Does the IOA Exclusively Govern Each Transaction in the Process to Transfer the Consumer's Electrical Distribution Service from FortisAB to EQUS

The AUC noted that if the IOA exclusively governs the transaction in the process to transfer the Consumer's service, the AUC does not have the jurisdiction to assess what charges FortisAB can levy on the Consumer.

The AUC determined that the IOA does not exclusively govern each transaction in the process of transferring the service. Rather, the T&Cs govern the terms and conditions applicable to the Consumer when it chooses to discontinue receiving service from FortisAB. As the AUC has the authority to approve FortisAB's T&Cs under the *Electric Utilities Act* ("*EUA*"), it can authorize terms and conditions (including exit charges) that apply when a customer chooses to discontinue receiving service from the respective utility, in this case, FortisAB.

The AUC decided in Decision 21148-D01-2016 that FortisAB had a duty under Section 105(1)(k) of the *EUA* to connect and disconnect customers in accordance with its approved tariff, regardless of the transfer provisions of the IOA. The AUC determined that the circumstances of the present case are similar and held that when the Consumer transfers its service, FortisAB has a duty to disconnect the Consumer in accordance with its approved tariff.

The AUC decided that the IOA contains a provision for payments between FortisAB and EQUS when a transfer of facilities occurs, but additional payments from a customer to either of them, such as exit charges, are not prohibited. The payment for transferred facilities included in the IOA does not relieve a customer of obligations assumed by obtaining electric distribution service from either FortisAB or EQUS. This, and how a disconnection may occur, is governed by the T&Cs.

As a result, the AUC determined that the IOA cannot specify or prohibit the T&Cs FortisAB may impose on its customers when they choose to disconnect from FortisAB's service. The IOA does not exclusively govern each transaction in the process to transfer the Consumer's service from FortisAB to EQUS.

Do FortisAB's Current T&Cs Permit FortisAB to Assess Exit Charges on the Consumer?

FortisAB relied on Section 7.5 regarding Charges Related to Permanent Disconnection of its T&Cs to levy the exit charges. FortisAB argued that the request by the Consumer to transfer its service to EQUS constitutes a wish to "permanently disconnect" its point of service. The definition of "permanent disconnection" in the T&Cs means "the cessation of Electricity Services resulting from removal of facilities…".

As mentioned in the previous section of this decision, the AUC found that FortisAB will disconnect the Consumer when its service is transferred to EQUS.

Concerning the permanent disconnection, the AUC also considered if the cessation would result from the removal of facilities. FortisAB submitted that when the Consumer is transferred, FortisAB would physically remove and salvage its meter(s).

In this regard, the AUC determined that the removal of the meter constitutes the removal of facilities within the meaning of a permanent disconnection. The AUC found the transfer of facilities to EQUS is equivalent to the removal of facilities that would satisfy the definition of "permanent disconnection" even though the facilities, except for the meter, are not physically removed. The intent of the permanent disconnection provision in FortisAB's T&Cs is that electricity service from FortisAB is ceased on a permanent basis.

The AUC found that the Consumer's request to transfer its service to EQUS constitutes a "wish to permanently disconnect its point of service" for the purposes of Section 7.5 of FortisAB's T&Cs, which allows FortisAB to assess exit charges.

Did FortisAB Properly Calculate the Exit Charges in Accordance with its T&Cs, and are the Resultant Exit Charges Just and Reasonable?

When a customer requests to connect to FortisAB's system, FortisAB usually constructs new facilities. To pay for the new facilities, generally, FortisAB invests in new facilities up to the maximum amounts established in its tariff. The investments are then included in FortisAB's rate base and depreciated over the lifetime of the assets, while a rate of return is earned on the undepreciated amount. The investment amount is intended to be recovered through the customer's rates over a defined period. Alternatively, if the costs exceed FortisAB's investment amount, the customer is required to pay a customer contribution.

The exit charges provided for in FortisAB's T&Cs serve to prevent FortisAB and other ratepayers from financial harm in the case that a customer decides to discontinue receiving service before the end of its investment term. When the Consumer transfers its service to EQUS, FortisAB will receive a payment from EQUS for the facilities that are transferred to EQUS.

The AUC considered whether the exit charges assessed by FortisAB should take into account the payment it will receive from EQUS. It was not convinced by FortisAB's submission that the payment from EQUS under the IOA and the customer's exit charge serve different purposes, do not necessarily relate to the same facilities, and should both be recovered. The AUC found that this position is inconsistent with how FortisAB accounts for the assets. It determined that the compensation FortisAB will receive from EQUS must be taken into account to calculate the exit charges payable by the Consumer, as "value of any facilities that may be salvaged" under Section 7.5(c) of the T&Cs.

The AUC held that FortisAB must reduce the exit charges by the payment it receives from EQUS for the transferred facilities. This payment must only be used to offset exit charges applicable to facilities that were subject to investment by FortisAB when the Consumer's service was constructed or upgraded.

Clarification of FortisAB T&Cs

The AUC determined that FortisAB's T&Cs require modification to clarify the applicability of the definition of "permanent disconnection" and associated exit charges. Modifications are also required to ensure that the method by which exit charges are calculated expressly contemplates the circumstances that can occur when a FortisAB customer transfers its service to an REA. FortisAB was directed to file an application proposing changes to the T&Cs on this issue by February 28, 2022.

Decision and Order

FortisAB was directed to recalculate the exit charges assessed to Jayson Schwab. In the recalculation, FortisAB must consider the payment it will receive from EQUS for the facilities that will be transferred. FortisAB was also required to file a post disposition document showing the recalculated charges and an application proposing amended T&Cs to clarify the related sections of the T&Cs.

FortisAlberta Inc. 2022 Annual Performance-Based Regulation Rate Adjustment, AUC Decision 26817-D01-2021

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2022 annual performance-based regulation ("PBR") rate adjustment filing from FortisAlberta Inc. ("FortisAB"). The AUC approved the 2022 distribution rates, options and riders, and corresponding rate schedules, the 2022 system access service ("SAS") rates, and the customer terms and conditions ("T&Cs") for electric distribution service. The AUC further approved customer contribution schedules and fee schedules.

Background

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor"). However, in place of the capital tracker mechanism employed in previous-generation PBR plans, the AUC divided capital funding into two categories: Type 1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with narrow eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provided an amount of capital funding for each year of the next-generation PBR plan based, in part, on capital additions made during the previous PBR term.

FortisAB's 2021 PBR rates were approved on an interim basis in accordance with the PBR framework in Decision 25843-D01-2020.

PBR Rate Adjustments

PBR Indices and Annual Adjustments

FortisAB's 2021 PBR plan provided a rate-setting mechanism based on a formula that adjusts customers' rates annually through an indexing mechanism plus specifically approved adjustments.

(a) I-X index

FortisAB calculated its 2021 I-X index to be 1.46 percent. The AUC approved the 2021 I factor of 1.76 and the resulting I-X index as calculated by FortisAB, as filed.

(b) Y and Z factor materiality threshold

FortisAB did not calculate a Y and Z factor materiality threshold as it did not apply for any new Y factor cost items or Z factors.

(c) Y factor

FortisAB applied for a Y factor amount of $0.8 million inclusive of carrying costs. The AUC approved the Y factor as filed.

(d) K-bar factor and K factor

The AUC approved FortisAB's applied-for 2022 K-bar funding of $84.5 million. In addition to its 2022 K-bar amount, this amount includes FortisAB's 2020 and 2021 K-bar true-ups for the actual cost of debt, as well as carrying costs.

FortisAB did not apply for any K factor rate adjustments for 2022.

(e) AESO Contributions Hybrid Deferral Account

The AUC accepted FortisAB's proposed hybrid deferral account treatment for the AESO Contributions Program. The AUC approved deferral account treatment of projects that received permits and licenses prior to December 31, 2017, and had already been reviewed by the AUC.

The AUC approved FortisAB's applied-for 2022 AESO contributions hybrid deferral amount of $13.1 million.

(f) Q Value

The AUC was satisfied with FortisAB's provided calculations and approved the 2021 Q value of 1.01 percent.

Forecast Billing Determinants and Variance Analysis

The AUC approved FortisAB's proposal to discontinue the use of adjustment factors and return to its approved billing determinant forecast methodology. The AUC found that FortisAB's 2022 forecasts do not differ significantly from the actuals experienced in the first six months of 2021. FortisAB's forecast 2022 billing determinants were developed using the same methods as previously approved by the AUC in decisions 2012-237, 2013-07220 and 24876-D01-2019.

<u>2020 Transmission Access Charge Deferral Account True-up</u>

In the current PBR plan, transmission access charge deferral account true-up ("TACDA") amounts are considered to be a part of the Y factor and are treated as a dollar-for-dollar flow-through of the AESO tariff charges.

Total Net True-up Amount

FortisAB applied for a net 2020 TACDA refund of $12.81 million to customers. This included a refund for all components of the TACDA aside from the border customer deferral. FortisAB indicated that in 2020, the total payments pertaining to service to its border customer suppliers were $0.57 million, while the receipts from the Power Pool were $0.28 million, resulting in a collection of $0.29 million.

The AUC approved the net refund of $12.81 million.

2022 Base Transmission Adjustment Rider and Effective Period

FortisAB calculated the 2022 base transmission adjustment rider ("TAR") by adding the 2020 TACDA true-up components and related carrying costs by rate class and divided these amounts by the forecast 2022 base transmission charges. The total net true-up amount results in a refund, but Rider J across individual rate classes and rural electrification association ("REA") wire owners will result in a collection from some customer classes and REA wire owners. The AUC approved the application of the 2020 annual TACDA true-up through a 2022 base TAR across 12 months.

<u>2022 PBR Rates</u>

System Access Service Rates

FortisAB indicated that its proposed 2022 SAS rates reflected the latest forecast of AESO volumes and prices. FortisAB forecast its 2022 transmission costs to be $738.8 million for distribution-connected customers. The 2022 Balancing Pool adjustment Rider was also updated to align with the AESO's Rider F rate of $2.20 per megawatt-hour. The AUC reviewed the calculations and approved the 2021 SAS rates as filed.

Distribution Rates

The AUC noted its consideration of the extraordinary economic realities facing Alberta. As a result of the circumstances, it found it reasonable for rate increases of the magnitude (10.3 percent) that would be experienced by Rate 61 customers to be mitigated.

The AUC approved FortisAB's calculations of its 2022 PBR rates on an interim basis, effective January 1, 2022. As a result of the rebasing process taking place in 2023, the AUC directed FortisAB to true-up the placeholders remaining in its 2022 distribution rates in a future proceeding to establish the 2023 rates.

Other Matters

Utility Payment Deferral Program Rate Rider

Under the Utility Payment Deferral Program ("UPDP"), enrolled electricity customers deferred payment of approximately $65.8 million in electricity bills. Of this amount, approximately $57.1 million was collected from enrolled electricity customers between June 19, 2020, and June 18, 2021. The AUC approved the collection of the remaining uncollected bill amounts of $8,776,854.70 by the AESO through rate Rider L in Decision 26684-D01-2021, which applied to all entities that receive SAS, with the exception of the City of Medicine Hat and BC Hydro at Fort Nelson, British Columbia.

Distribution-Connected Generation Credit - Option M

Distribution-connected generation ("DCG") credits are the payments that FortisAB, among others, provides to DCG connected to its distribution systems. These credits are calculated and paid pursuant to provisions within its tariff. In FortisAB's distribution tariff, this is referred to as Option M and this cost is recovered from ratepayers as part of its collection of SAS costs. In Decision 26090-D01-2021, the Commission determined that the Rate Demand Transmission Service portion of the DCG credit mechanism were to be diminished over a four-year transition period until they are discontinued in 2026.

FortisAB added the multipliers prescribed by the AUC into its rate schedules but did not account for the effects of the multipliers on its SAS cost forecast. FortisAB's SAS cost forecast assumed that DCG credits were paid as if the AUC prescribed multiplier did not exist. FortisAB stated that it took this approach to limit the regulatory burden necessary to incorporate the multipliers in its SAS cost forecast. FortisAB proposed to assume no effect of the multiplier on its SAS cost forecasts in 2022 and, and then in 2024 and 2025 assume a multiplier of zero in its SAS cost forecast. The AUC accepted this approach and directed its application by FortisAB in future SAS cost forecasts.

Terms and Conditions of Service and Fee Schedules

FortisAB complied with the AUC's directions to make specific changes to the T&Cs of service. The AUC approved FortisAB's filed customer and retailer T&Cs, customer contribution, and customer fee schedules as part of its 2022 distribution tariff on a final basis.

Financial Reporting Requirements

The AUC was satisfied that FortisAB had complied with the financial reporting requirements.

***FortisAlberta Inc. Decision on Application for Review and Variance of Decision 25916-D01-2021 2022 Phase II Distribution Tariff Application*, AUC Decision 26757-D01-2021**
Review and Variance - Costs

In this decision, the AUC approved the application from FortisAlberta Inc. ("FortisAB") for review and variance ("R&V") of Decision 25916-D01-2021 regarding FortisAB's 2022 Phase II distribution tariff application (the "Decision") on the grounds related to the Alberta Electric System Operator ("AESO") contribution costs. All other grounds for review were denied.

Background

The review application concerns the hearing panel's findings in Section 6 of the Decision regarding FortisAB's distribution cost allocation and rate design as FortisAB's service area overlaps with the service areas of rural electrification associations ("REAs"), who provide electrical service to their cooperative members. Specifically, FortisAB was concerned with the AUC's findings questioning whether costs incurred by FortisAB as a result of integrated operations with REAs should be borne by their customers through the distribution tariff and how these costs should be removed from rates charged to FortisAB's distribution customers.

The review application primarily related to findings regarding areas where FortisAB and certain REAs' service areas overlap. FortisAB also alleged that the AUC relied on the wrong evidence when denying a proposal to reallocate shared system costs among small capacity rate classes.

Review Panel Findings

Questions of Law

Subsequent to the amendment of Rule 016: *Review of Commission Decisions,* errors of law can no longer provide the basis for a review application. While FortisAB raised issues as errors of fact or mixed fact and law, the review panel found that two grounds constitute allegations of errors of law, and therefore are outside the scope of Section 5 of Rule 016. The two grounds were FortisAB's claim that the AUC acted in breach of natural justice and procedural fairness; and that the AUC failed to consider, or misinterpreted Section 122 of the *Electric Utilities Act* ("*EUA*").

Section 2 of Rule 016

FortisAB submitted that considering the importance of the alleged errors, their implications, and their relevance to the AUC's central ratemaking function and the overarching regulatory compact if the review panel finds that any of the alleged errors are errors of law, it should exercise its discretion under Section 2 of Rule 016 to review the Decision on its own motion.

The review panel found that the basis of the request for review based on an error of law on its own motion does not justify the exercise of its discretion under Section 2 of Rule 016. It further agreed with the submission from EQUS REA that in the circumstances of this application, it should be left to the Court of Appeal of Alberta to address errors of law.

Section 5(1)(a) of Rule 016

As a preliminary matter, the AUC held that some of FortisAB's submissions were made on the basis that the hearing panel improperly weighed evidence. The AUC found that it was not the review panel's task to retry the application and second guess the weight assigned to evidence by the hearing panel. FortisAB's request to review some of the findings by the hearing panel on this bases was consequently denied.

(a) The AUC erred in finding that it does not have authority to approve the type of costs titled 'FortisAB costs to serve REAs under integrated operations':

The review panel noted that going forward, consistent with *Ball v Imperial Oil Resources Limited*, the AUC may consider a ground alleging a failure to consider relevant evidence to be an error of law, and therefore outside the scope of Rule 016. Despite this, for the purposes of this proceeding, the review panel was prepared to consider FortisAB's ground as an error of mixed fact and law.

The review panel found that the hearing panel did not err in its interpretation of the nature of the costs ordered removed from FortisAB's revenue requirement. The review panel found that the hearing panel was aware of the facts and circumstances and considered FortisAB's submissions that its distribution assets were built, and the associated costs were incurred, to serve FortisAB customers. The hearing panel therefore did not err in failing to consider FortisAB's evidence.

FortisAB's second claim was that the hearing panel made the errors of fact, or mixed fact and law, in finding that the proper avenue for FortisAB to recover its costs to serve REAs was under the process set out in the *Roles, Relationships and Responsibilities Regulation* ("*3R Regulation*"). The AUC disagreed.

The review panel found that FortisAB's submission that the hearing panel should have made express reference in the Decision to the recent arbitration awarded between itself and EQUS, or to its term, to be an allegation that the hearing panel failed to address a central concern raised by the parties in its reasons. Lack of sufficiency of reasons would, if proven, be a breach of procedural fairness. The AUC noted that it has previously characterized errors in process as errors in law, and Rule 016 specifies that no review is available on errors of law. As such, these are not grounds for which review is available, and the application for review on this ground is dismissed.

With regard to FortisAB's argument that the hearing panel ignored clear and uncontested evidence that FortisAB could only have a reasonable opportunity to recover the costs to serve REAs if such costs were confirmed to be reasonable under its own tariff, the review panel noted that this argument was made in the original proceeding and that re-arguing the same point and suggesting that different conclusions could be or should have been reached does not amount to a reviewable error.

The review panel found that FortisAB did not demonstrate that an error of fact exists on a balance of probabilities in respect of its allegation that the hearing panel failed to consider or misapprehended evidence regarding the status of the integrated operation agreement negotiation and arbitrations, as was required by Section 5(1)(a) of Rule 016. FortisAB's request for review on this ground was therefore denied.

With respect to the unintended circumstances, FortisAB argued that the hearing panel erred when it failed to discharge its legislated duty under Section 122 of the *EUA* by directing FortisAB to remove from its revenue requirement an estimate of its costs to serve REAs under integrated operations for 2023. FortisAB emphasized that it is legislatively required to incur these costs to provide safe and reliable distribution service to its ratepayers. As a result of the Decision, FortisAB can no longer recover these costs within the ratemaking framework. FortisAB argued that this was not considered in the Decision.

Overall, the review panel noted that there was insufficient clarity regarding the alleged error to allow the review panel to determine if the ground alleged is an error of mixed fact and law or an error of law. With respect to FortisAB's allegation that the hearing panel failed to consider all the evidence on the consequences of increased regulatory/business risk and capital market reactions, including expectations of higher rates of return, the review panel found that FortisAB did not demonstrate that an error of mixed fact and law exists on a balance of probabilities. FortisAB's request for a review on this ground was therefore denied.

(b) The AUC erred in finding that 'even if the AUC had the authority to approve the FortisAB costs to serve REAs under integrated operations as part of FortisAB's tariff, it would decline to do so as it would be contrary to the public interest':

In the Decision, the hearing panel stated that even if it had the authority to include the FortisAB costs to serve REAs under integrated operations in FortisAB's tariff, the inclusion would be contrary to the public interest.

The review panel denied FortisAB's request for a review on this ground for two reasons. First, the review panel agreed with the position of the Utilities Consumer Advocate ("UCA") that the hearing panel's findings in question were *obiter dicta*. Given that these findings are unnecessary to the Decision, they do not constitute an error material to the Decision.

Next, it appears to the review panel that FortisAB argues, in relation to the second and third alleged errors, that the hearing panel made a finding based on no supporting evidence. These are allegations of errors of law and therefore outside the scope of Rule 016. The application for review on these grounds was dismissed.

(c) The AUC erred in fact by relying on the wrong evidence to deny FortisAB's proposed reallocation of shared system costs among small capacity rate classes:

FortisAB proposed to reallocate a portion of costs among its small capacity customer rate class. The hearing panel denied the proposal in Section 4.6 of the Decision. The hearing panel found that FortisAB provided insufficient evidentiary support to justify the proposed reallocation of costs between small capacity rate classes.

The review panel agreed with arguments made by FortisAB and the UCA supporting the presence of an error of fact. However, the AUC found that the error was not material to the Decision and denied a review on this ground.

(d) The AUC erred in fact by including AESO contribution costs in the revenue removal:

FortisAB submitted that the hearing panel erred in fact in finding that it did not have authority to approve AESO contribution costs allocated to REAs, totaling $1.188 million in 2017. FortisAB submitted that the alleged error results in an internal inconsistency in the Decision, which is a material error and should be corrected.

FortisAB alleged that the hearing panel did not apply the correct legal standard to a set of facts. This indicated an error of mixed fact and law.

The review panel found that FortisAB provided sufficient evidence and rationale in the review proceeding to demonstrate that AESO contribution costs allocated to REAs could be transmission costs associated with AESO tariff amounts, and part of FortisAB's legislated system access service ("SAS") obligations.

The review panel was persuaded that an error of mixed fact and law where the legal principle is not readily extricable, which is material to the decision, exists on a balance of probabilities. Accordingly, a review on this ground was allowed.

In the Decision, the hearing panel noted that the cost for services provided to the REAs by FortisAB are part of FortisAB's distribution tariff due to express statutory language.

The hearing panel denied a new section of terms and conditions of service that would allocate and recover AESO contribution costs from REAs for transmission upgrades to support REA electricity supply requirements. The review panel held that if it were to find that AESO contribution costs allocated to REAs are SAS costs, properly within FortisAB's distribution tariff, the review panel would also have to assess who should bear these costs under the AUC's duty to set a just and reasonable tariff. This included examining whether these costs should be flowed through to REAs.

The review panel found that the evidence demonstrated that AESO contribution costs allocated to REAs are a result of FortisAB providing SAS to REAs. The review panel determined that AESO contribution costs allocated to REAs are SAS costs and are properly part of FortisAB's distribution tariff. As a result, the Decision will be varied accordingly.

The review panel further found that since AESO contribution costs allocated to REAs result from FortisAB arranging for the provision of SAS to REAs, it is just and reasonable for these costs to be flowed through to REAs, just as other SAS costs are because REA members obtain SAS through FortisAB.

<u>Decision</u>

The AUC allowed the application for review and variance of Decision 25916-D01-2021 to the extent it related to the AESO contribution costs and varied the hearing panel's findings in the Decision.

***Landowners Near the Approved Route for Transmission Line 459L Decision on Preliminary Question Application for Review of Decision 26171-D01-2021 AltaLink Management Ltd. Provost to Edgerton Transmission Development*, AUC Decision 26888-D01-2021**

Facilities - Review and Variance

In this decision, the AUC denied the application from Ken Leskow, Mary Abbot, Len Nash, Erick Corkum, Ty Miller, Jason Bishop, and George and Marilynn Bishop (the “review applicants”) to review and vary AUC Decision 26171-D01-2021.

Review Application and Background

Decision 26171-D01-2021 (the “Decision”) relates to the proposed construction and operation of a 240 kilovolt (“kV”) transmission line, designated as Transmission Line 459L (the “Project”).

The review applicants stated that they have lands that will be crossed over, or are adjacent to, the route preferred by AltaLink Management Ltd. (“AML”) and approved by the AUC in the Decision. Five of the applicants filed statements of intent to participate (“SIPs”) and stated concerns with the impact of the Project on their lands or their use of the lands.

The review panel held that the following findings were made by the original hearing panel:

- The preferred route will have a significantly lower overall impact than the alternate route, particularly since the preferred route parallels an existing transmission line for nearly 99 percent of its length, while only approximately three percent of the alternate route parallels an existing transmission line.

- The preferred route is located in road allowances for much more of its length as compared to the alternate route.

- The more extensive use of developed road allowances and paralleling an existing disturbance also resulted in the preferred route being more suitable than the alternate route from an environmental impact perspective.

- The preferred route would be shorter and have fewer impacts on native vegetation and wetlands. For additional reasons discussed in the Decision, the hearing panel accepted that the environmental impacts of the routing options favoured approval of the preferred route.

The process and the AUC’s authority to review and vary decisions is set out in Section 10 of the *Alberta Utilities Commission Act* (“*AUC Act*”) and Section 5 of Rule 016: *Review of Commission Decisions*. In this proceeding, the AUC considered the preliminary question: deciding whether there are grounds to review the Decision.

Issues and Review Panel Findings

Section 5(1)(b) Grounds – Previously Unavailable Facts

The review applicants submitted that they have evidence that was not made available in the AUC’s hearing as the applicants were unaware of the hearing process. The applicants' submission implied that the information in question is not new but is the same information that the review applicants would have provided to the hearing panel if they had participated in the hearing.

The AUC denied a review on these grounds, as it had not been indicted that there are previously unavailable or newly discovered facts that are material to the Decision.

Section 5(1)(d) Grounds – Decision Made Without Hearing or Notice

The review applicants asserted that the AUC failed to give proper notice of the hearing and this prevented them from filing evidence and participating in the hearing.

(a) Was notice of the hearing given to the review applicants?

The review panel noted that the review application was focused on the applicants' difficulties accessing the AUC's eFiling system and with email notifications from the system. The review panel noted that the original notice of hearing was mailed, not emailed, as no person had registered to participate in the eFiling system at the time of issuance. The AUC also noted that five of the eight review applicants took steps to file SIPs in Proceeding 26171 prior to the filing deadline. This strongly suggests that each of them had received notice of the hearing and understood the need to file submissions by the deadline.

The review panel found that notice of the hearing was given to the review applicants who met the test for standing set out in Section 9 of the *AUC Act*, in accordance with Section 7 of Rule 007.

(b) Did the notice of hearing provide adequate information about how to participate in the hearing in Proceeding 26171?

The review applicants submitted that they did not know what to do to participate in the hearing.

The review panel reviewed the information about participation, and the requirements to participate in the hearing provided to the review applicants. The review panel also noted that in May 2021, the AUC issued a letter setting out the protocols for the virtual AUC hearing followed by an anticipated schedule. The review panel found that the information included in the notices of hearing and the process letters issued from the eFiling system to persons who registered for the proceeding included adequate and understandable instructions on how to participate.

(c) Did the AUC process fail the review applicants, specifically the eFiling system?

Process failures identified by the review applicants include assertions that can be characterized as problems with the AUC's eFiling system or the notifications that were issued to them by the system.

The review applicants submitted that they either did not receive proper assistance from AUC staff following requests for assistance. The AUC, however, found that there was insufficient evidence to support these claims. The submissions lacked sufficient particularity related to when and from who the review applicants requested assistance.

The review panel determined that the applicants did not submit sufficient evidence to allow for the conclusion that the process failed the applicants. Where sufficient information was provided regarding participants' contact with the AUC, AUC staff assisted participants. The review panel was not persuaded that the review applicants took steps to have any problems experienced addressed by AUC staff.

<u>Decision</u>

In answering the preliminary question, the AUC found that the review applicants have not met the requirements for a review of Decision 26171-D01-2021 and the application for review and variance was dismissed.

***Pteragen Canada Inc. Peace Butte Wind Power Project*, AUC Decision 26787-D01-2021**
Facilities - Wind

In this decision, the AUC approved applications from Pteragen Canada Inc. ("Pteragen") for permission to construct and operate the 122-megawatt ("MW") Peace Butte Wind Power Plant (the "Power Plant") and a collector substation designated as the Tothill 219S Substation (collectively, the "Project"). The AUC also approved the application for permission to connect four wind turbines to the distribution system of FortisAlberta Inc. ("FortisAB") and to AltaLink Management Ltd.'s ("AML") transmission system.

Applications

In 2013 Pteragen received approvals for the original Peace Butte Wind Power Project. The approvals were rescinded in 2021 as significant time had passed since the approvals were issued, and Pteragen was planning to file a project amendment due to project design and layout revisions.

The Power Plant will be constructed near Medicine Hat and will consist of 22 5.54-MW wind turbines with a hub height of 114 meters and a rotor blade length of 78.3 meters. The Power Plant differs from the power plant applied for in 2013, as the proposed turbines have a larger capability than the originally approved wind turbines, which significantly reduces the number of turbines for the Project from 60 to 22.

AUC Findings

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

The shadow flicker assessment indicated that two active dwellings within 1.5 kilometers would receive shadow flicker from the Project. The AUC noted that the shadow flicker assessment used conservative assumptions and did not consider screening from clouds, trees, or other obstacles. The AUC accepted that shadow flicker impacts may be less than predicted for the Project.

Alberta Environment and Parks ("AEP") ranked the Project an overall moderate risk to wildlife and wildlife habitat. AEP noted that Pteragen sited the majority of its collector lines above ground which differs from the requirements identified in AEP policy. AEP stated that the alternative mitigation proposed by Pteragen reduced but did not eliminate the increased risk, and therefore the specific risk to wildlife and wildlife habitat has been assessed as high.

As mitigation measures, Pteragen proposed to design and construct the above-ground collector lines following the Avian Power Line Interaction Committee ("APLIC") standards. Pteragen further proposed to mark all segments of the above-ground collector lines, including those crossing coulees or wetlands, with bird diverters to minimize the potential for bird collisions. The AUC was satisfied that the Project's potential effects on wildlife and wildlife habitat will be adequately mitigated with the diligent implementation of the mitigation measures committed to by Pteragen.

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

AUC Decision

Pursuant to sections 11, 14, 15, 18 and 19 of the *Hydro and Electric Energy Act,* the AUC approved the applications to construct and operate the Power Plant and substation and to connect the four wind turbines to FortisAB's distribution system.

***Tidewater Midstream and Infrastructure Ltd. and WCSB Blockchain Infrastructure Ltd. Ram River Isolated* Power *Plant*, AUC Decision 26912-D01-2021**

Facilities - Natural Gas and Steam

In this decision, the AUC approved the application from Tidewater Midstream and Infrastructure Ltd. ("Tidewater"), on behalf of WCSB Blockchain Infrastructure Ltd. ("WCSB"), for the construction and operation of the 84-megawatt ("MW") natural gas and steam-fired combined-cycle Ram River Isolated Power Plant (the "Power Plant").

Application

The Power Plant will consist of two natural gas-fired turbine generators, two heat recovery steam generators, and one steam turbine generator. The Power Plant will be located within the existing Ram River Gas Plant, approximately 50 kilometers southwest of the town of Rocky Mountain House.

The Power Plant will not be connected to the Alberta Interconnected Electric System and will be used to supply on-site data centers. Both the Power Plant and data centers would be owned and operated by WCSB.

The application included a participant involvement program, a noise impact assessment ("NIA"), air quality assessment report and an environmental evaluation report. The application also included confirmation that Tidewater has a site-specific emergency response plan for the Ram River Gas Plant.

AUC Discussion and Findings

The AUC determined that the application provides the information required by Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines.*

The NIA indicated that the nighttime cumulative sound level would be 40.8 A-weighted decibels ("dBA"), which exceeds the nighttime permissible sound level of 40 dBA. Tidewater committed to installing an intake air silencer or acoustic louvers on the intake air penthouse, an addition or upgrade to the silencers on the proposed gas turbine exhausts, and the upgrading of cooler fans to achieve compliance with the permissible sound level.

The NIA also found that the Power Plant would exceed low frequency noise situation thresholds outlined in Rule 012: *Noise Control*. However, as there are no residences within 1500 meters of the Power Plant, an exceedance at the nearest residence was determined to be unlikely. Tidewater committed to conducting a comprehensive sound survey if a noise complaint from a residence is received. The AUC was satisfied with this evaluation and commitment.

Decision

The AUC acknowledged that Tidewater applied for an exemption pursuant to Section 13 of the *Hydro and Electric Energy Act* ("*HEEA*"). However, the AUC has decided to issue an approval under Section 11 of the *HEEA* because of the capability of the Power Plant.

The AUC approved the application to construct and operate the Ram River Isolated Power Plant pursuant to Section 11 of the *HEEA.*

***TransCanada Energy Ltd. Saddlebrook Solar Storage Project*, AUC Decision 26572-D01-2021**
Facilities - Solar Power

In this decision, the AUC approved the application from TransCanada Energy Ltd. ("TCE") for approval to construct and operate a 102.5-megawatt ("MW") solar power plant, a 6.5-MW storage facility, and the Saddlebrook 303S Substation (the "Project").

Introduction

The solar facility would have approximately 420,000 bifacial solar panels and will be connected to the proposed substation by a 34.5-kilovolt ("kV") collector system. The battery storage facility will consist of a flow battery system and will have a storage capacity of 40-megawatt hours ("MWh"), be charged from the solar power plant, and provide electric energy to the Alberta Electric System ("AIES"). The Project will be located on 135 hectares of land within the Saddlebrook Industrial Park in Aldersyde, near Okotoks.

The AUC granted standing to Sharon and Brian McCaughan, who filed a statement of intent to participate ("SIP") and own land approximately 250 meters from the Project boundary. Their SIP indicated they were opposed to the Project because they were concerned it would decrease their property value and have negative health, visual, and wildlife impacts.

AUC Findings

The AUC determined that the applications meet the information requirements set out in Rule 007: *Application for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines.* The AUC found that the Project, as applied for, abides by all applicable rules and standards.

The concerns raised by S. and B. McCaughan in their SIP and subsequent correspondence were not supported by any evidence. The AUC was consequently not able to assess the likelihood of those impacts or the extent to which S. and B. McCaughan might be affected by the Project.

The AUC noted that the solar glare assessment submitted with the application indicated that the effect of solar glare on persons traveling on the transportation routes and at the dwellings does not pose a safety hazard to those individuals. This assessment assumed that the solar panels would use an anti-reflective coating. As a condition of approval, the AUC imposed as a condition of approval that TCE uses an anti-reflective coating on the solar panels of the Project. Further, it required that TCE submits a report to the AUC detailing any complaints or concerns TCE receives or is made aware of regarding solar glare from the solar facility during its first year of operation, as well as its response to the concerns and complaints. TCE was directed to file this report no later than 13 months after the solar facility becomes operational, even if no complaints are made.

As TCE had not finalized the selection of equipment for the Project, the AUC required that TCE submit final project updates to the AUC once the equipment selection and layout of the Project are finalized. The updates must include the final information related to the solar facility and the battery storage facility, to confirm that the facilities have stayed within the specified allowances for solar and battery storage facilities.

Finally, to ensure compliance with Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants*, the AUC imposed as a condition of approval that TCE submits an annual post-construction monitoring survey report to Alberta Environment and Parks ("AEP") and the AUC within 13 months of the solar facility becoming operational, and on or before the same date every subsequent year for which AEP requires surveys.

Decision

Pursuant to Sections 11, 14, 15 and 19 of the *Hydro and Electric Energy Act*, the AUC approved the applications from TCE to construct and operate the Saddlebrook Solar Storage Project including the power plant, storage facility and substation.

***Travers Solar GP Ltd. Application for an Order Permitting the Sharing of Records Not Available to the Public Between Travers Solar GP Ltd., Travers 2 Solar LP and URICA Energy Real Time Ltd.*, AUC Decision 26970-D01-2021**

Market Oversight and Enforcement - FEOC

In this decision, the AUC approved the application from Travers Solar GP Ltd. ("Travers Solar") for an order permitting it to share records pertaining to the electricity and ancillary services markets that is not available to the public under Section 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*").

Introduction and Procedural Background

Travers Solar filed an application seeking permission to share records not available to the public, including energy price, volume pairs, and available capability, between Travers Solar, Travers 2 Solar LP ("Travers 2 Solar"), and URICA Energy Real Time Ltd. ("URICA") relating to the to-be-constructed 465-megawatt ("MW") Travers Solar Power Plant (the "Power Plant"). The Power Plant will be located in the village of Lomond.

AUC Findings

Subsection 3(3) of the *FEOC Regulation* authorizes the AUC to issue an order permitting the sharing of records on any terms and conditions that the AUC considered appropriate. The AUC found that the necessary and applicable requirements for the approval were met.

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

The AUC further found that total offer control of Travers Solar, Travers 2 Solar, and URICA were well below the maximum of 30 percent, set out in Subsection 5(5) of the *FEOC Regulation*.

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

The AUC approved the application.

***Versorium Energy Ltd. Green Glade 1 Distributed Energy Resource Power Plant*, AUC Decision 27045-D01-2021**

Facilities - Gas

In this decision, the AUC approved the applications from Versorium Energy Inc. ("Versorium") for permission to construct and operate the natural gas-fired 5.044-megawatt ("MW") Green Glade 1 Distributed Energy Resource Power Plant (the "Power Plant"), near Provost, Alberta. The AUC also approved the application to connect the Power Plant to FortisAlberta Inc.'s ("FortisAB") electrical distribution system (collectively, the "Project").

Applications

The Power Plant and connection to the electrical distribution system will be located on private, cultivated land. The Project would include two gas-fired reciprocating engines, with a nominal capability of 5.044 MW, a switchgear building, a generator step-up transformer, a low-pressure natural gas pipeline to connect to the Natural Gas Co-op 52 Ltd. natural gas system, and a distribution line to connect to the FortisAB electric distribution system.

The applications included a noise impact assessment, air quality assessment report, environmental evaluation report, and a letter of non-objection from FortisAB, confirming that it would allow the interconnection. Versorium indicated that it expects an in-service date of the Power Plant and interconnection of October 31, 2022, and requested a construction completion date of December 31, 2023, to account for any unforeseeable delay.

AUC Findings

The AUC reviewed the applications and found that the information requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* have been met. The AUC further found that the assessments and reports included with the applications indicated that the Power Plant and interconnection will meet the requirements of Rule 012: *Noise Control* and the *Alberta Ambient Air Quality Objectives.*

Versorium submitted an *Environmental Protection and Enhancement Act* application to Alberta Environment and Parks on December 10, 2021, and had not received feedback on the application by the date of this decision. The AUC accepted Versorium's submission that the Project will not result in significant adverse effects on the environment.

<u>Decision</u>

The AUC found the applications to be in the public interest in accordance with Section 17 of the *Alberta Utilities Commission Act.* Pursuant to Section 11 of the *Hydro and Electric Energy Act* and consequently approved the applications for construction and operation of the Power Plant. The AUC also approved the application to connect the Power Plant to the FortisAB electric distribution system pursuant to Section 18 of the *Hydro and Electric Energy Act.*

***Versorium Energy Ltd. Netook 1 Distributed Energy Resource Power Plant*, AUC Decision 27044-D01-2021**
Facilities - Gas

In this decision, the AUC approved the applications from Versorium Energy Inc. ("Versorium") for permission to construct and operate the natural gas-fired 5.044-megawatt ("MW") Netook 1 Distributed Energy Resource Power Plant (the "Power Plant"), northeast of Olds, Alberta. The AUC also approved the application to connect the Power Plant to FortisAlberta Inc.'s ("FortisAB") electrical distribution system (collectively, the "Project").

<u>Applications</u>

The Power Plant and connection to the electrical distribution system will be located on private, cultivated land. The Project would include two gas-fired reciprocating engines, with a nominal capability of 5.044 MW, a switchgear building, a generator step-up transformer, a low-pressure natural gas pipeline to connect to the Foothills Natural Gas Co-op natural gas system, and a distribution line to connect to the FortisAB electric distribution system.

The applications included a participant involvement program, a noise impact assessment, air quality assessment report, environmental evaluation report, and a letter of non-objection from FortisAB, confirming that it would allow the interconnection. Versorium indicated that it expects the Project to be in service by February 2023 and requested a construction completion date of December 31, 2023, to account for any unforeseeable delay.

<u>AUC Findings</u>

The AUC reviewed the applications and found that the information requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* have been met. The AUC further found that the assessments and reports included in the applications indicated that the Power Plant and interconnection will meet the requirements of Rule 012: *Noise Control* and the *Alberta Ambient Air Quality Objectives.*

Versorium submitted an *Environmental Protection and Enhancement Act* application to Alberta Environment and Parks on December 10, 2021, and had not received feedback on the application by the date of this decision. The AUC accepted Versorium's submission that the Project will not result in significant adverse effects on the environment.

<u>Decision</u>

The AUC found the applications to be in the public interest and consequently approved the applications for construction and operation of the Power Plant pursuant to Section 11 of the *Hydro and Electric Energy Act*. The AUC also approved the application to connect the Power Plant to the FortisAB electric distribution system pursuant to Section 18 of the *Hydro and Electric Energy Act.*

CANADA ENERGY REGULATOR

***NOVA Gas Transmission Ltd. Applications Regarding Pioneer South Pipeline Acquisition Decision and Orders*, CER Letter Decision and Orders MO-041-2021 and XG-015-2021**
Facilities

In this decision, the CER considered two applications filed concurrently for the Pioneer South Pipeline acquisition. The first was an application filed under paragraph 181(1)(b) and Section 226 of the *Canadian Energy Regulator Act* (the "*CER Act*") to acquire the approximately 30 km Pioneer South Pipeline, Zeta Lake Receipt Meter Station, and in-line inspection launcher facility (the "Assets") from ATCO Gas and Pipelines Inc ("AGP") subject to a positive AUC decision and to roll the purchase price of the Assets plus adjustments and project costs into the NGTL System rate base. The second was an application filed under Section 214 of the *CER Act* for an order authorizing the continued operation of the Assets under CER jurisdiction, effective on the closing date. NOVA Gas Transmission Ltd. ("NGTL") requested leave to open the Assets pursuant to Section 213 of the *CER Act* effective on the closing date and an exemption from the provisions of paragraph 180(1)(a) of the *CER Act* in respect of the Assets as they are currently in operation.

The Assets are the westernmost part of the Pioneer Pipeline, an approximately 131 km provincially regulated pipeline. On June 15, 2021, the AUC approved ATCO's acquisition of the Pioneer Pipeline from Pioneer Pipeline Inc. (AUC Decision 25937-D01-2021) and the disposition of the Assets to NGTL (AUC Decision 26189-D01-2021).

The CER approved the Pioneer South Pipeline acquisition as set out in the applications as it is limited to existing Assets that are fully constructed and operational and will align the ownership and operation of the Pioneer Pipeline with the footprints of the Integration Agreement. The CER issued Order MO-041-2021 granting NGTL leave to purchase the Assets from ATCO pursuant to paragraph 181(1)(b) of the *CER Act* and to roll the purchase price of the Assets into the NGTL System rate base as well as Order XG-015-2021 granting NGTL leave to open the Assets.

<u>Procedural Fairness</u>

Views of the Parties

Western Export Group ("WEG") took the position that it does not consider the CER's process to comply with the principles of natural justice and procedural fairness. WEG stated that no intervenor had an opportunity to submit information requests or cross-examine NGTL and that the CER placed the onus on WEG and other intervenors to prove that the acquisition and the premium price were not justified and prevented any review of the Western Alberta System ("WAS") interconnect-only alternative.

CER Analysis and Findings

The CER found that parties had a meaningful opportunity to raise and reply to concerns through their submissions and their response to the comment process. The CER has discretion to tailor its process to the nature and scope of an application before it. The CER considered the process it used to hear and decide this matter to be appropriate because there is no statutorily prescribed process associated with the applications nor was there any basis, given the nature of the interests at stake in this proceeding, for a legitimate expectation that a certain procedure including some form of cross-examination must be followed.

<u>Need and Alternatives</u>

Views of the Parties

WEG took issue with NGTL's application to acquire the ~30 km portion of the Pioneer Pipeline from AGP because, among other things, there is no present or future unmet need. If additional gas supply is required by the current users of the Pioneer Pipeline, there is no reason to conclude that the required quantities cannot be delivered by existing infrastructure or with the addition of a simple interconnection between the Pioneer Pipeline and NGTL System. WEG also argued that the need for the Pioneer Pipeline beyond year 15 is highly uncertain as a number of the TransAlta power plants are no longer in operation or scheduled to be retired imminently, and the need for gas at the Sundance and Keephills power plant units has changed materially. WEG also stated that NGTL never provided evidence on why an interconnect-only facility investment would not be a better alternative.

NGTL submitted that there is a growing demand for natural gas in the Wabamun area driven by the conversion of existing power generation facilities from coal to natural gas and that the acquisition of the Pioneer Pipeline was the optimal solution to meet its service requirements. The acquisition and integration of the Pioneer Pipeline attracted contracts for three distinct transportation services: Firm Transportation Delivery (“FT-D”), Firm Transportation Receipt (“FT-R”), and Other Services Extraction (“OS-EXT”). These included contracts from TransAlta for executed 15-year FT-D service for 400,000 GJ/d at its Keephills and Sundance power plants. Tidewater also entered into an incremental FT-R contract with an eight-year term for 47MMcf/d and an OS-EXT contract for 3,500 GJ/d.

CER Analysis and Findings

The CER found that NGTL demonstrated the need for the acquisition of the Assets by illustrating the growing demand for natural gas in the region and how the Assets are required to meet it. The addition of the Assets into the integrated system provides an increase in capability, including upstream approved expansions between 2022 and 2024. The CER also finds that the volumes and terms of the TransAlta and Tidewater incremental contracts further justify the acquisition. The CER was also satisfied with NGTL’s explanation and analysis of the alternatives that were considered.

<u>Purchase Price</u>

Views of the Parties

WEG submitted that the prudency of the acquisition was not demonstrated. The proposed acquisition cost of the entire Pioneer Pipeline by AGP is estimated more than $30 million higher than the book value at the time of its acquisition. The Pioneer South Pipeline, which NGTL proposes to acquire from AGP, is priced as a percentage of the whole and therefore includes a portion of that premium. WEG stated that no acquisition premium was justified.

The Utilities Consumer Advocate (“UCA”) references its evidence from the AUC proceeding that took issue with the ~$35 million gain (or 15.9 percent premium) that Pioneer and its owners Tidewater and TransAlta would see from the sale of the pipeline.

NGTL submitted that it was not purchasing the Assets at a premium. The purchase price for the approximately 130 km Pioneer Pipeline was $255 million, which represented the fair market value of the Pioneer Pipeline as negotiated between arm’s length entities. NGTL and AGP agreed on a purchase price of $64.975 million for the Assets subject to purchase price adjustments and that the price included the length of the pipeline value, the full cost of the Zeta Lake receipt meter station, and the net book value of capital upgrades to the Assets while under AGP ownership.

CER Analysis and Findings

The CER confirmed that there are circumstances in which they may not allow the inclusion of all or a portion of a facility’s acquisition costs in the rate base. In these specific circumstances, the CER found that the full purchase price of the Assets should be rolled into the NGTL System rate base as proposed by NGTL. The CER was of the view that while NGTL is paying a purchase price that effectively includes a premium over the net book value as it stood prior to AGP’s acquisition ($8.6 million for their portion of the Assets), it is proper for NGTL to proportionally allocate 30km of the overall Pioneer Pipeline purchase price in a manner consistent with the Integration Agreement’s geographic footprints.

Engagement with Commercial Third Parties

Views of the Parties

WEG listed several issues that were not apparent during the Tolls, Tariff, Facilities and Procedures ("TTFP") meeting and therefore disagreed that there were no outstanding concerns with NGTL's acquisition. However, in WEG's September 2, 2021 submission, they stated that they had no comments regarding NGTL's engagement with third parties.

Tidewater Midstream and Infrastructure Ltd. ("Tidewater") and TransAlta stated that they are members of the TTFP Committee and that NGTL's engagement with commercial parties was detailed, fulsome, and adequate.

NGTL provided an overview of their engagement with commercial third parties commencing with a facility notification presentation to the TTFP on July 14, 2020. Engagement activities included a notification on the TTFP website, a verbal update at a TTFP meeting, a meeting with WEG on November 6, 2020, filing a project notification, and the presentation of NGTL's 2020 financial plan to the TTFP.

CER Analysis and Findings

The CER was satisfied that NGTL's notification and engagement with commercial third parties were adequate. The CER was of the view that commercial third parties that could be affected by the decision are aware of the applications and have had the opportunity to comment should they wish to.

Greenhouse Gas Emissions and Climate Change

Views of the Parties

WEG provided comments on NGTL's IR No. 3 response regarding greenhouse gases and climate change, specifically referencing the CER Filing manual guidance for a net-zero emissions plan. WEG submitted that NGTL had not provided this information, and as a result, the record was incomplete.

NGTL stated that they did not address greenhouse gas or climate change on the basis that the applications were to acquire and operate existing assets, not to construct and operate new facilities.

CER Analysis and Findings

The CER agreed with NGTL's statement that they are not constructing and operating new facilities, and therefore a net-zero plan was not required. The CER reminded NGTL that it must adhere to and implement Environment and Climate Change Canada's *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds* (Upstream Oil and Gas Sector), as applicable, to the operation of the Assets.