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DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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This monthly report summarizes matters under the jurisdiction of the AER, the AUC and the NEB and proceedings resulting from AER, AUC and NEB decisions. For further information, please contact Rosa Twyman at Rosa.Twyman@RLChambers.ca or John Gormley at John.Gormley@RLChambers.ca.

IN THIS ISSUE:

ALBERTA COURT OF APPEAL

Percy v. Value Creation Inc. (2018 ABCA 50)
Application for Stay Pending Appeal

In this decision, the Alberta Court of Appeal ("ABCA") considered applications by Greg and Barbara Percy (the "Percys") for:

(a) a stay of an AER hearing scheduled for February 6, 2018, pending the Percys' appeals of:

(i) AER letter decisions issued on December 7 and December 8, 2017, denying the Percys' request to delay the February 6, 2018, hearing and to expand the scope of that hearing; and

(ii) the AER decision denying the Percys' request for reconsideration of EUB Decision 2005-079;

and

(b) an adjournment of the Percys application to the ABCA for permission to appeal the December 7 and 8th AER decisions.

The ABCA granted the request to adjourn the application for permission to appeal the December 7 and 8, 2017 AER decisions.

The ABCA denied the Percys' application for a stay of the AER panel hearing scheduled for February 6, 2018.

Background

The ABCA set out the following background information:

- Through a subsidiary called BA, VCI planned to upgrade the refinery in the Heartland Upgrader Project (the "Project"). In 2005, BA received approval from the Alberta Energy & Utilities Board ("EUB"), the AER's predecessor, in EUB Decision 2005-079 to conduct upgrades: (the "2005 Upgrade Approvals Decision").
- The Project was delayed and, in the wake of BA becoming insolvent, in 2014 (according to the Percys) VCI obtained permission to transfer BA's approvals for the Project from BA to VCI.
- On September 26, 2017, the AER issued a public Notice of Hearing for VCI's applications to amend existing AER approvals concerning continuation of the Project. The Percys submitted a request to participate, granted by the AER hearing panel on October 31, 2017. The hearing was set to commence February 6, 2018.
- The October 31 AER panel decision also stated that the scope of the hearing would be limited to considering the following matters: the amendments contemplated by the applications; the potential health, safety, and environmental impacts; the emergency preparedness; and the emergency protection zone.
- On December 7, 2017, the AER denied a request to expand the scope of the February 6, 2018 hearing.
- On December 8, 2017, the AER sent a letter to the Percys and VCI agreeing to accept submissions on whether the 2005 Upgrade Approvals Decision should be reconsidered.
- On January 5, 2018, the Percys applied to the ABCA for permission to appeal the AER letter decisions of December 7 and 8th, 2017, that is, to appeal the AER decisions to carry on with the February 6, 2018 hearing and not to expand its scope.
- On January 29, 2018, the AER issued its decision denying the Percys' request for reconsideration of the 2005 Upgrade Approvals Decision.
- The Percys submitted that they intended to apply for permission to appeal that decision, and sought an adjournment so that both applications for permission to appeal could be heard together.

ABCA Findings

ABCA Denied Stay of February 6 AER Hearing

The Percys sought to stay the AER panel hearing scheduled for February 6, 2018, pending the ABCA's disposition on the applications for leave to appeal.

The Percys argued that allowing the February 6, 2018 AER panel hearing to proceed would further entrench AER decisions already made. They submitted that the February 6, 2018 proceedings were limited in scope to matters such as establishing safety zones and would not address ongoing concerns, such as the devaluation of their property.

The ABCA denied the stay based on its findings that:

(a) Rule 14.48 of the *Alberta Rules of Court* provided the ABCA authority to grant a stay pending appeal, but it was questionable whether that language included circumstances where a person had filed an application for permission to appeal, but that application had not been decided;

(b) Even assuming rule 14.48 allowed for a stay pending the hearing of an application for permission to appeal, the Percys had not yet provided arguments on the merits of their leave applications, let alone the appeals themselves; and

(c) Consequently, the ABCA was not in a position to determine whether the Percys had raised arguable issues on appeal.

Additionally, the ABCA found that the AER was entitled to deference as to how it arranges its processes in order to fulfill its statutory mandate.

The ABCA noted its previous statement that in " . . . the context of setting a hearing schedule and refusing an adjournment of the commencement date of a hearing, this Court should be loath to interfere with the Board's process, absent egregious conduct by the Board ..."; and an administrative decision maker's ruling on whether to adjourn its proceedings is a discretionary one, attracting a high standard of appellate review: *BP Canada Energy Co. v. Alberta (Energy & Utilities Board)*, 2004 ABCA 75.

The ABCA found that in these circumstances, a stay was not warranted.

ABCA Grants Request for Adjournment of Application for Permission to Appeal AER Decisions

Given there was an outstanding application for leave to appeal the December 7 and 8th AER decisions and an impending application to appeal the January 29th, 2018 AER decision, the ABCA granted an adjournment of that yet-to-be-heard leave application.

Conclusion

The ABCA denied the Percys' application for a stay of the AER panel hearing scheduled for February 6, 2018.

The ABCA granted the request to adjourn the application for permission to appeal the December 7 and 8, 2017 AER decisions.

ALBERTA ENERGY REGULATOR

TransCanada Pipelines Limited – Applications for the White Spruce Pipeline Project Fort McKay Area (2018 ABAER 001)
Pipeline Project

In this decision, the AER considered applications by TransCanada Pipelines Limited ("TransCanada") to construct two crude oil pipelines, referred to as the White Spruce Pipeline Project (the "Project").

In this decision, the AER approved the Project for the reasons summarized below.

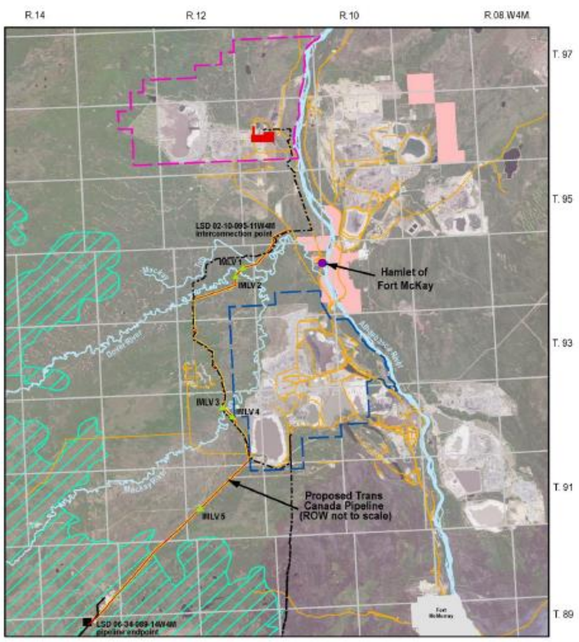
The Project

The Project consisted of two pipelines:

- The first pipeline would be 508 millimetres (mm) in diameter and about 50 metres (m) in length.
- The second pipeline would be 323.9 mm in diameter and 71.5 kilometres (km) in length.

The Project would deliver synthetic crude oil ("SCO") from Canadian Natural Resources Limited's ("CNRL") Horizon processing plant to the Grand Rapids Pipeline GP Ltd. MacKay Terminal for delivery to markets.

Figure 1: Project Map



The proposed Project is indicated in orange on Figure 1.

Legal Framework

The AER explained that:

(a) as set out in section 2(1) of the *Responsible Energy Development Act* ("*REDA*"), the AER's mandate is to provide for the efficient, safe, orderly, and environmentally responsible development of energy resources in Alberta; and

(b) therefore, in this case, the AER had to decide whether approving the Project was consistent with the AER's mandate.

The AER determined that the following were the key questions it had to decide:

- Is the project needed to provide for the efficient and orderly development of Alberta's energy resources?
- What are the potential adverse effects on aboriginal participants and can they be adequately mitigated?
- What are the potential environmental effects of the project and can they be adequately mitigated?
- Is the project designed in a way that it can be constructed and operated safely?

Need for Project

To determine whether the project was needed, the AER considered the following:

(a) the total SCO production expected from the Horizon plant after the phase 3 expansion;

(b) the transportation capacity of existing pipeline facilities;

(c) if increased production from the Horizon plant would exceed the existing transportation capacity; and

(d) whether other options existed to transport increased production from the Horizon plant.

The AER found that:

(a) the daily average future capacity of the Horizon plant would gradually exceed 250,000 bbl/d of SCO once the expansion is complete;

(b) the Horizon pipeline operated by Pembina could handle up to 250 000 bbl/d of SCO from the Horizon plant; and

(c) there were no other viable options to transport increased production from the Horizon plant.

Given the above, the AER found that the proposed White Spruce Pipeline project was needed to provide for the efficient and orderly development of Alberta's energy resources and would not result in unnecessary proliferation.

Potential Adverse Effects on Aboriginal Participants

The Project would be located within Fort McKay First Nation's ("Fort McKay") traditional territory.

The AER considered how the project could affect Fort McKay and their ability to exercise their treaty and aboriginal rights. The AER explained that Fort McKay's Treaty 8 and aboriginal rights were constitutionally protected and included their right to hunt, fish, trap, and gather for food, social, cultural, and consumption purposes and to use and enjoy their reserve lands.

Fort McKay First Nation ("Fort McKay") raised concerns about the Project's impacts on:

(a) watercourse crossings and that the Project would affect water quality and fish due to the potential for bank erosion and leaks;

(b) wildlife and habitat;

(c) herbicide use; and

(d) cumulative effects of industrial development on exercising their treaty and aboriginal rights.

Water Crossings

The AER noted that:

(a) The Project would cross 31 waterbodies, including crossings at three main watercourses: the Dover River, Mackay River, and an unnamed tributary to the Mackay River;

(b) TransCanada would use horizontal directional drilling ("HDD") at a minimum depth of 48m below the watercourse bed for the three main watercourse crossings; and

(c) For the remaining watercourse crossings, TransCanada would construct open-cut crossings during frozen ground conditions to minimize disturbance.

The AER found that:

(a) The use of HDD at the proposed depth would protect the three main watercourses from disturbance to fisheries and habitat; and

(b) Minimal disturbance techniques, erosion control procedures, and monitoring during and after construction would mitigate potential adverse effects on the remaining watercourse crossings and Fort McKay's rights to use those watercourses.

Based on the above, the AER concluded that the proposed watercourse crossing methods would avoid or minimize impacts to Fort McKay's rights to fish, travel, and use the waterbodies for cultural enjoyment.

Wildlife and Habitat

Fort McKay expressed concerns about the project's impacts on wildlife in the area. They were primarily concerned about the impacts on their treaty and aboriginal rights focused on caribou and moose.

The AER noted that:

(a) TransCanada's caribou protection plan set out mitigation strategies to reduce adverse effects on caribou and caribou habitat; and

(b) TransCanada set out general mitigation measures in its environmental protection plan to minimize impacts to all wildlife, including caribou and moose, by:

    (i) paralleling existing linear disturbance for the entire project footprint;

    (ii) completing construction during winter conditions; and

    (iii) using minimal surface disturbance techniques to facilitate quicker vegetation recovery.

The AER found that Fort McKay's wildlife concerns had been addressed and that any incremental effects of the project on Fort McKay's rights to harvest wildlife would be adequately mitigated by TransCanada's caribou and environmental protection plans, along with the following conditions imposed by the AER:

- If moose were identified in the immediate vicinity (right-of-way plus 100 metres) of the construction zone, TransCanada must immediately suspend work in the vicinity of the moose, assess the situation, and allow construction to resume only when the moose have moved safely away from the construction zone.
- If a trench must be left open overnight or unattended, sloped subsoil ramps must be placed at the ends of the open trench to create egress for wildlife that might enter the trench.

- At wildlife migration or travel corridors identified by TransCanada or the AER, TransCanada must install breaks in windrows to allow wildlife movement across the project footprint.

The AER found that TransCanada's commitment to restrict the general application of herbicides near traditional land-use sites, together with its more general mitigation measures on herbicide use, represented a responsible approach to avoiding potential impacts to Fort McKay's exercise of its treaty and aboriginal rights.

Cumulative Effects

The AER found that Fort McKay's concerns about cumulative effects on their treaty and aboriginal rights were general in nature and not supported by specific evidence.

The AER further noted that the Aboriginal Consultation Office indicated that the Government of Alberta ("GoA") was working through the Lower Athabasca Regional Plan to respond to cumulative impact concerns. Neither of these frameworks was yet completed or in effect. The AER noted that when complete, such frameworks should provide clearer direction and guidance to the AER in determining issues like those raised by Fort McKay.

Consultation: Aboriginal Consultation Office Reports and Recommendations

The AER explained that the GoA is required to consult with aboriginal groups when decisions under its jurisdiction may adversely affect treaty and aboriginal rights. Under section 21 of *REDA*, the AER has no jurisdiction to assess the adequacy of Crown consultation associated with the rights of aboriginal people. This authority remains with the GoA and is carried out by the ACO.

Under the *Aboriginal Consultation Direction* Ministerial Order, the AER cannot make a decision on an energy application requiring aboriginal consultation until it has requested and received the ACO's advice on consultation adequacy and on any required action to address potential adverse effects on the treaty and aboriginal rights or traditional uses.

In this decision, the AER considered two reports from the ACO:

(a) the first ACO report addressed the project consultation and potential adverse impacts on Fort McKay's treaty and aboriginal rights; and

(b) the second ACO report considered the record of the AER proceeding and addressed matters not previously addressed in the consultation process.

In those reports, the ACO found consultation with Fort McKay to be adequate. The ACO made recommendations to reduce impacts to wildlife and the AER to require actions consistent with or equally effective as TransCanada's mitigation plans to address these impacts.

For the reasons summarized above, the AER found TransCanada's proposed avoidance and mitigation measures, along with the conditions imposed by the AER, would adequately mitigate potential adverse impacts on Fort McKay's treaty and aboriginal rights.

<u>Potential Environmental Effects</u>

Key Wildlife and Biodiversity Zones

Key Wildlife and Biodiversity Zones are identified and mapped by the GoA. The AER noted that the Project would be located within a designated Key Wildlife and Biodiversity Zone.

The AER found that the use of horizontal directional drilling techniques to install the pipeline beneath the Mackay River biodiversity zone would adequately mitigate construction and long-term effects on the Key Wildlife and Biodiversity Zone.

Vegetation

The AER found that:

(a) the proposed vegetation control within 5 m on either side of the pipeline's centreline for a 15 m right-of-way would leave a revegetated strip of 2.5 m on either side of the right-of-way; and

(b) this would not make a significant contribution to restoration of critical habitat within the West Side Athabasca Range, particularly given the lengthy timeline for regeneration to mature forest.

Therefore, the AER directed, as a condition of approval, that TransCanada prepare and implement habitat restoration in the West Side Athabasca Range to offset the effects of the Project.

<u>Conclusion</u>

The AER determined that:

(a) the impacts of the Project, after implementation of TransCanada's commitments and mitigation plans and the conditions imposed by the AER, can be mitigated to a level consistent with responsible development; and

(b) the Project was needed to provide for the efficient, orderly, and environmentally responsible development of Alberta's energy resources.

The AER, therefore, approved the Project with conditions.

Declaration Naming Donald Allen Currie under Section 106 of the Oil and Gas Conservation Act
Section 106 of Oil and Gas Conservation Act – Enforcement

In this letter to Mr. Currie, the AER provided its reasons for issuing a deceleration under section 106(1) of the *Oil and Gas Conservation Act* (the "*OGCA*"), naming Donald Allen Currie as a person in direct or indirect control of Sabanero Energy Corporation ("Sabanero"), a company that contravened or failed to comply with AER orders and has a debt owing to the AER.

Declaration under Section 106 of the *OGCA*

The AER explained that *OGCA* section 106 applies where the AER considers it in the public interest to make a declaration naming one or more directors, officers, agents, or other persons who, in the AER's opinion, were directly or indirectly in control of a licensee, approval holder, or working interest participant that has (i) contravened or failed to comply with an order of the AER; or (ii) has an outstanding debt to the AER, or to the AER to the account of the orphan fund, in respect of suspension, abandonment, or reclamation costs.

AER Findings

The AER found that:

(a) Sabanero held 58 well licenses, 3 facility licenses and 10 pipeline licenses, many of which had been orphaned due to noncompliances;

(b) Sabanero failed to comply, or even attempt to comply, with AER orders including:

  (i) a December 22, 2015 Order regarding a pipeline failure;

  (ii) Closure/Abandonment, issued after Sabanero did not pay its required security deposit of over $1.7 million; and

  (iii) an Environmental Protection Order, requiring reclamation and remediation;

(c) Saberno owed $14,628.90 to the AER in outstanding levy fees;

(d) Many of Sabanero's licences had been designated as orphan for purposes of abandonment, as Sabanero effectively abdicated any responsibility for them; and

(e) as the director of Sabanero at the time of the company's noncompliances and nonpayment of debts owing to the AER, Donald Allen Currie was and is a person in control of Sabanero.

The AER stated that Sabanero's ongoing failure to comply with AER requirements demonstrated a blatant disregard for the regulatory regime. Further, failure to pay amounts owing to the AER and abandon and reclaim facilities left a substantial weight on the already over-burdened Orphan Well Association.

The AER found that Sabanero's actions and inactions undermined the regulatory system and posed an unacceptable risk to public safety and the environment.

The AER concluded that issuing a declaration was necessary to deter future noncompliances and uphold the credibility of the regulatory system and AER enforcement processes.

ALBERTA UTILITIES COMMISSION

Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities – First Compliance Proceeding (Decision 22394-D01-2018)
PBR Plans – Rebasing Applications – K-factor Mechanism – Distribution Utilities

In this decision, the AUC considered the compliance filings submitted by the distribution utilities pursuant to the Commission directions set out In Decision 20414-D01-2016 (Errata) (the "2018-2022 PRB Plans Decision"), which established the overall framework for the 2018-2022 PBR plans.

The decision applied to the following Alberta distribution utilities (the "Distribution Utilities"):

- AltaGas Utilities Inc.;
- ATCO Electric Ltd. (distribution);
- ATCO Gas and Pipelines Ltd. (distribution);
- ENMAX Power Corporation (distribution);
- EPCOR Distribution & Transmission Inc. (distribution); and
- FortisAlberta Inc.

Due to ENMAX being subject to an individual incentive-based regulation plan, certain AUC findings and directions in this decision were individualized to ENMAX's unique plan. Those differences are not discussed in this summary.

For the reasons summarized below, the AUC directed each of the Distribution Utilities to file a second compliance filing by March 1, 2018. In addition to addressing the directions in this decision, the AUC directed each utility to apply for 2018 PBR rates in its second compliance filing.

First Generation PBR Framework Approved in Decisions 2012-237

The first generation PBR framework approved in Decision 2012-237 provided a rate-setting mechanism based on a formula that adjusted rates annually by means of an indexing mechanism that tracks the applicable inflation rate ("I") to the prices of inputs used by utilities, less a productivity offset factor ("X"). Under this I-X mechanism, a utility's revenues are not linked to its costs during the PBR term, with the exception of specifically approved adjustments, namely: (i) an adjustment for certain flow-through costs that should be recovered or refunded from or to customers directly (a Y factor), and (ii) an adjustment to account for certain exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism (a Z factor), and (iii) certain capital costs (capital trackers) collected directly from customers through K factor rate adjustment ("K Factor"), including amounts to fund necessary capital expenditures.

2018-2022 PBR Plans Decision

Parameters Approved 2018-2022 PRB Plan Decision

In the 2018-2022 PRB Plans Decision, the AUC established the parameters to be included in the 2018-2022 PBR plans for the Distribution Utilities, with the four main parameters being: (i) rebasing and the going-in rates for the next generation PBR term, (ii) the X factor, (iii) the treatment of capital additions, and (iv) the calculation of the return on equity ("ROE") for reopener purposes.

In the 2018-2022 PBR Plans Decision:

- The AUC explained that "rebasing" refers to the exercise of generally realigning revenues and costs in anticipation of, or at the end of, a PBR plan term, in order to establish new going-in rates for the next generation PBR plan.
- To minimize the potential distorting incentives that could arise during the last year of a PBR term, the AUC decided to set the going-in rates for the 2018-2022 PBR plans on the basis of a notional 2017 revenue requirement that would be calculated using the actual pre-2017 costs, adjusted as required for anomalies.
- The AUC kept the same methodology for the I factor as used in the 2013-2017 PBR plans, calculated as a weighted average of two inflation indexes. The AUC set the X factor to be 0.3 per cent for the 2018-2022 term, based on updated industry total factor productivity growth studies and inclusive of a stretch factor.
- The AUC approved the continuation of the Y factor and Z factor rate-adjustment mechanisms for the 2018-2022 PBR term.

Going-in rates for the 2018-2022 PBR Plans

In the 2018-2022 PRB Plans Decision, the AUC directed each of the Distribution Utilities to file an application to determine a notional 2017 revenue requirement. This notional 2017 revenue requirement would be used for the sole purpose of establishing the going-in rates for the first year of the 2018-2022 PBR term.

Specifically, the AUC directed that the components of a utility's proposed 2017 notional revenue requirement (Phase I applications) be determined in the following manner:

- **Operating and maintenance (O&M) costs** calculated using actual O&M costs for the utility's lowest-cost year excluding the last year of the term, 2017, restated to 2017 dollars, with adjustments as necessary to reflect material anomalies. The AUC approved the use of a Q-factor, which allows for adjustments to O&M expenses due to customer growth.
- **Rate Base** calculated:
  - (i) using the 2016 actual closing rate base as a starting point;
  - (ii) adding:
    - (i) capital additions covered by the I-X in 2017, calculated as the average actual capital additions over the 2013-2016 period, restated to 2017 dollars; or
    - (ii) capital additions subject to capital tracker treatment in 2017, equal to the approved 2017 forecast capital tracker capital additions (to be updated later to approved actual data);
  - (iii) adjusting the rate base by removing utility assets, as directed in prior asset disposition decisions; and
  - (iv) adjusting to reflect the finalization of placeholder amounts currently under review by the Commission in separate proceedings.
- **Depreciation expenses** calculated using the Distribution Utility's most recent approved depreciation methodologies applied to the notional rate base, as determined in the above manner.

Phase II applications would be accepted for consideration sometime following the commencement of the next generation PBR plans. Any changes to rates approved in Phase II applications – e.g. requesting the AUC consider a new COS or depreciation study – would only apply on a prospective basis. Following the approval of an updated Phase II study for a specific distribution utility, the AUC stated that it would not consider further Phase II applications by that utility during the 2018-2022 PBR plan period.

Efficiency Carry-over Mechanism

The AUC noted that a utility's incentive to find efficiencies weakens as a PBR term nears an end, unless there is an efficiency carry-over mechanism ("ECM"). An ECM seeks to incent late term efficiency improvements by providing an associated financial "reward" carried-over into the subsequent PBR term.

In the 2018-2022 PRB Plans Decision, the AUC approved an ECM ROE add-on applied to the 2017 mid-year rate base and escalated by the approved I-X value for each of the subsequent years from 2018 to 2019.

<u>Proposed Anomaly Adjustments to O&M Expenditures</u>

The AUC noted that:

- In the 2018-2022 PBR Plans Decision, it did not prescribe a specific method to account for anomalies in determining the lowest-cost year for O&M expenditures.
- However, by following the calculations embedded in the rebasing template provided by the AUC, a distribution utility would identify all anomalies, both positive and negative and adjust the actual O&M costs in each year for the identified anomalies restated in 2017 dollars.
- After accounting for anomalies and converting to 2017 dollars, the lowest-cost year for O&M expenditures would be selected from the subject years.

Determining Lowest Cost Year

The AUC found that the majority of the Distribution Utilities first determined the lowest-cost year for O&M expenditures and then identified anomalies pertaining to that lowest-cost year. Certain utilities also reviewed their O&M costs for the full period (2013-2016) to determine whether there were anomalies that would identify a different lowest-cost year.

The AUC found that:

(a) the approach of identifying the lowest-cost year for O&M expenditures and then applying the anomaly adjustments relevant to that year, was not as rigorous as the approach incorporated by the AUC in its template; and

(b) identifying anomalies pertaining to only one year, in isolation, may have resulted in distribution utilities ignoring potentially material positive or negative anomalies in other years.

Notwithstanding these observations, the AUC accepted the general overview approach for identification of the lowest-cost year for O&M expenditures finding that such an approach:

(a) was a reasonable response, given the AUC did not prescribe a specific method for determining the lowest-cost year; and

(b) was generally consistent with the principles reflected in the 2018-2022 PBR Plans Decision.

Based on the above, the AUC accepted the lowest-cost year for O&M identified by each of the Distribution Utilities for the purposes of calculating the notional 2017 revenue requirements O&M component.

Anomalies

For the reasons summarized below, the AUC denied all the Distribution Utilities' applied-for anomalies.

The AUC noted that the template it provided for re-basing calculations involved identifying all of the anomalies, both positive and negative.

Based on its findings in the 2018-2022 PBR Plans Decision, the AUC found that, in order to qualify as an "anomaly" for rebasing purposes, a proposed cost adjustment may be positive or negative but must exhibit all of the following characteristics:

(a) must be specific and identifiable;

(b) must be required to account for unique existing or anticipated costs;

(c) must be material;

(d) must not reflect actual or forecast 2017 costs; and

(e) must not be costs that each distribution utility, operating under the incentives of the PBR mechanism, unencumbered by incentives inconsistent with the PBR incentives, would have incurred in 2017.

The AUC noted that all parties relied on certain of these criteria from the 2018-2022 PBR Plans Decision, but neglected other parts of the AUC's description.

The AUC did not approve any of the anomalies proposed by the parties. The AUC found that although some of the proposed anomalies may have satisfied the first three anomaly criteria (specific, identifiable, unique, and material), certain of the anomalies proposed by the parties did not satisfy the fourth criterion (not actual or forecast costs) and none of the anomalies proposed by the distribution utilities satisfied the fifth criterion (costs inconsistent with incentives).

<u>K-bar Incremental Capital Funding</u>

Overview of K-bar Mechanism Approved in 2018-2022 PBR Plans Decision

In place of the capital tracker mechanism used in the first generation PBR framework, in the 2018-2022 PBR Plans Decision, the AUC approved a modified capital tracker mechanism with narrower eligibility criteria. Specifically, the AUC approved a capital funding mechanism whereby capital projects are to be categorized as either Type 1 or Type 2.

For Type 1 capital, the AUC approved a modified capital tracker mechanism with narrow eligibility criteria, namely:

(a) The project must be of a type that is extraordinary and not previously included in the distribution utility's rate base; and

(b) The project must be required by a third party.

The revenue requirement associated with approved amounts for Type 1 projects would be collected from ratepayers by way of a "K factor" adjustment.

Type 2 capital projects are all other capital additions that do not meet the type 1 project criteria. The revenue requirement associated with approved amounts for Type 2 programs would be collected from ratepayers by way of a K-bar factor adjustment to the annual PBR rate-setting formula.

The AUC directed an initial K-bar capital factor ($\overline{K}_0$) be established, equal to the incremental capital funding for all Type 2 capital in 2018. The base K-bar would be calculated by using an accounting test similar to the test used during the 2013-2017 PBR term. Specifically, the three steps for calculating the 2018 base K-bar amount are as follows:

- Step 1: Calculate the revenue provided under the I-X mechanism for each project or program included in Type 2 capital.
- Step 2: Determine the revenue requirement associated with the 2018 notional capital additions for each Type 2 project or program. The notional 2018 capital additions amount is determined as the 2013-2016 average capital additions amount, net of retirements using the 2013-2016 average, both converted to 2018 dollars using the prescribed conversion factors.
- Step 3: Determine the base K-bar ($\overline{K}_0$) amount by subtracting the first component from the second component on a project or program basis, and then summing all of the resulting amounts, which may include both positive and negative values.

The base K-bar determined the incremental funding in 2018. For the subsequent years 2019 through 2022, the K-bar incremental capital funding for a particular year ($\overline{K}_t$) would be calculated by escalating the base K-bar amount in accordance with the following formula:

$\bar{K}_t = \bar{K}_{t-1} x\ (\bar{K}_0) * \left(1 + (I_t - X) * (1 + (I_{t-1} - X)\right) \ldots$

Where:

$\bar{K}_t$ = K-bar factor for current year;

$\bar{K}_{t-1}$ = K-bar from the previous year;

$\bar{K}_0$ = 2018 base K-bar;

I_t = inflation factor for current year;

I_{t-1} = inflation factor from the previous year;

X = productivity factor; and

$(1 + (I_{t-1} - X)) \ldots = (1 + (I_{t-1} - X)$ multipliers for all previous years.

The AUC referred to this formula as the "annual K-bar escalation formula."

AUC Concludes Refinements Required for Calculating 2018 Base K-bar and Annual K-bar Escalation Formula

For the reasons summarized below, the AUC determined that it was necessary to refine the mechanics for calculating the 2018 base K-bar ($\bar{K}_0$) and the annual K-bar escalation formula to more accurately reflect the intended principle established for K-bar funding.

Incremental K-bar Calculations Diverged from Historical Average Capital Additions

For the reasons summarized below, the AUC found that the mechanics of annual K-bar escalation formula established in the 2018-2022 PBR Plans Decision resulted in an annual funding level for the 2019-2022 period that diverged from what the AUC intended when it established the principle behind the K-bar mechanism. Namely: To provide incremental funding sufficient to allow for annual net capital additions equal to the historical average adjusted to current year dollars.

The AUC found that:

(a) the 2018 base K-bar amount, calculated in the manner prescribed in the 2018-2022 PBR Plans Decision, provided incremental capital funding that allowed a utility to make capital additions at a level sufficient to provide the Distribution Utilities with a reasonable opportunity to earn a fair return in the context of the entire PBR plan, subject to mid-year convention considerations (discussed below);

(b) however, for the years 2019 through 2022, as a result of the interaction of the base K-bar accounting test with the annual K-bar escalation formula, the K-bar mechanism would provide funding that would allow the Distribution Utilities to make capital additions at a level different from the prescribed historical average of net capital additions; and

(c) the level of K-bar funding that emerged was larger than the level of K-bar funding necessary to fund the prescribed historical average of net capital additions.

The AUC noted potential reasons contributing to this divergence, including:

- The effect of the mid-year convention: If a utility makes capital additions in 2017 at a level materially different from the prescribed historical average of net capital additions, the base K-bar amount was skewed up or down as the second half of the 2017 additions became included in the revenue requirement calculations in 2018. Therefore, the 2018 base K-bar amount was not strictly reflective of the 2018 notional additions, which were based solely on the prescribed historical average of net capital additions.
- The possible inability of the annual K-bar escalation formula to account for the effects of accumulated depreciation on expected returns: This could result because the annual K-bar escalation formula continued to provide the prior year K-bar amount in addition to including another year's worth of base K-bar adjusted to current year dollars. The assets added in prior years become one year older each year, meaning they would experience one more year of depreciation expense added to accumulated depreciation. Under traditional rate-base rate-of-return regulation, the expected return on the prior year assets would go down each year because accumulated depreciation reduces the rate base. However, the K-bar formula did not have any sort of downward adjustment that would reflect the actual need for the utility to meet its return obligations on a lower-valued rate base.

The AUC found that although the above issues may have contributed to the divergence, the magnitude of their respective contribution towards the observed divergence could not be determined conclusively. Nor could the AUC determine the possible roles of other factors, such as the locked-in nature of base K-bar values for I factor, Q and WACC parameter values for the entire PBR term, in explaining the divergence.

The AUC concluded that, regardless of the reasons why, the mechanics of annual K-bar escalation formula established in the 2018-2022 PBR Plans Decision resulted in an annual funding level for the 2019-2022 period that diverged from what the AUC intended when it established the principle behind the K-bar mechanism.

The AUC determined that the best way to resolve this issue was to consider alternative approaches to calculating K-bar.

Alternative Approaches to Calculating K-bar

The AUC found that it was necessary to consider an alternative approach to determining K-bar that lessened the sensitivity of the value of K-bar funding to the manner in which it was calculated.

The AUC directed that for the years 2019 through 2022, the K-bar amount should be calculated by way of an annual parameter adjustment to reflect the I factor, Q and WACC approved for that year. In the AUC's view, the advantages of using an annual K-bar parameter adjustment approach included the following:

(a) it eliminated the possibility that an unreasonable assumption would become embedded in the 2018 base K-bar, which would then be propagated for the duration of the 2018-2022 PBR term if the original annual K-bar escalation formula were used;

(b) it eliminated the effects of the mid-year convention issues because the annual parameter adjustment was based on rate-base rate-of-return principles. Therefore, the effects on the 2018 rate base of the second half of 2017 capital additions being materially higher or lower than the prescribed historical average of net capital additions were limited to the 2018 calculation; and

(c) it eliminated the effects of accumulated depreciation issues because the annual parameter adjustments utilize rate-base rate-of-return calculations that, by definition, account for accumulated depreciation.

Calculating the 2018 Base K-bar Amount

The AUC directed that for 2018, the base K-bar be calculated as set out in the 2018-2022 PBR Plans Decision (summarized above), with one modification. In Step 2 of the K-bar calculation, the average K-bar capital additions by project for 2013-2016 would be calculated and converted to 2018 dollars using both the I-X index and Q value approved for each year prior to and including 2018.

Calculating the K-bar amount for 2019-2022 PBR term

For each of 2019 through 2022, the AUC provided instructions for determining the K-bar annual adjustment, summarized as follows:

- Step 1: Calculate the revenue requirement that is recovered in the base rates under the I-X mechanism for Type 2 K-bar projects or programs for each of the years 2019 through 2022.
- Step 2: Calculate the notional revenue requirement for Type 2 K-bar projects or programs for each of the years 2019 through 2022.
- Step 3: (i) Calculate the K-bar as the difference between the K-bar capital-related revenue requirement required on a projected basis by program or project (from Step 2) and the capital-related revenue recovered in the base rates by program or project (from Step 1) for each year from 2019 to 2022. The result is the capital funding shortfall or surplus amount for each program or project for 2019 to 2022; and (ii) Sum the capital funding shortfall and surplus amounts, including both negative accounting test results and positive accounting test results without any materiality considerations, for all Type 2 projects and programs from Step 3(i) to get the total K-bar for each of 2019 through 2022.

Under the annual parameter adjustment approach, the K-bar amount would be calculated each year by adjusting the I, Q and WACC parameters to reflect the approved values for that year:

I factor	I factor for each year, as approved by the AUC in the applicable annual PBR rate adjustment filings for that year.
Q values	Q values for each year, as approved by the AUC in the applicable annual PBR rate adjustment filings for that year.
WACC	WACC used in the first component of the accounting test should be based on the assumptions used in 2017 going-in rates for the cost of debt, ROE and capital structure. The application of the I-X mechanism to the revenue requirement built into going-in rates ensures that the current year's cost of capital is adequately accounted for without the need for a specific adjustment.
	The second component of K-bar accounting test will use ROE and capital structures approved by the Commission for that year in the relevant GCOC proceeding (or other proceedings that make directions related to cost of capital).

Other Parameters	Other than the I factor, Q and WACC parameters that will be adjusted every year, the annual K-bar calculation relies on parameters that will not change through the PBR term

Conclusion

The AUC concluded that:

(a) the K-bar mechanism, as refined by the AUC in this decision, would produce the intended incentives for managing capital costs thereby benefiting both customers and the Distribution Utilities; and

(b) when the refined K-bar mechanism is considered in conjunction with the other integrated components of the 2018-2022 PBR plans, would result in just and reasonable rates.

Second Rebasing Compliance Filing

The AUC provided a number of specific directions to each of the Distribution Utilities requiring modification to various components of the notional 2017 revenue requirement and base K-bar amount (not summarized).

The AUC directed each of the Distribution Utilities to file a second rebasing compliance filing application reflecting the directed modifications by March 1, 2018, which are to include:

(a) the rate component that calculates the 2018 PBR rates; and

(b) proposed distribution rate schedules to be effective April 1, 2018.

Following the determination of the 2018 PBR rates in the rebasing second compliance proceeding, the AUC stated that Distribution Utilities may file applications to update depreciation studies if they so choose.

Dalziel Enterprises Ltd. - Payment in Lieu of Notice Charge Complaint with FortisAlberta Inc. (Decision 22796-D01-2018)

Complaint Application – Terms & Conditions – Payment in Lieu of Notice Charge

In this decision, the AUC considered a complaint filed by Dalziel Enterprises Ltd. ("DEL") against FortisAlberta Inc. ("Fortis"). In its complaint, DEL asked the AUC for relief from the payment in lieu of notice ("PILON") provisions in Fortis' Customer Terms and Conditions of Electric Distribution Service ("T&Cs").

For the reasons summarized below, the AUC determined that Fortis' T&Cs, including the PILON provisions, applied to DEL and that the PILON provisions were applied to DEL in a manner consistent with the AUC's original approval of the T&Cs. The AUC therefore dismissed DEL's complaint.

Background

DEL operated a hay processing plant in Innisfail, Alberta on land leased from Red Deer County. DEL began receiving electricity services from Fortis' predecessor in July 2000.

In mid-August 2016, DEL requested adjustments to reduce its peak demand. DEL received a review of minimum (ROM) proposal from Fortis that offered two options to reduce the expected peak demand from 330 kilowatts (kW) to 11 kW and to change the rate assigned to the service from Rate 61 (general service) to Rate 41 (small general service):

- Option 1: Immediate reduction of the monthly minimum demand with a PILON: distribution customer exit charges of $ 12,652.58 ($ 4,981.83 for transmission and $ 7,068.25 for distribution, plus $ 602.50 Goods and Services Tax); or
- Option 2: No cost with a 7-month notice period. The service would continue to bill on a monthly minimum demand of 220 kW until the notice period expires.

DEL verbally requested to disconnect its service through its competitive retailer, ENMAX Energy Corporation ("ENMAX"). Fortis issued a termination of service proposal letter to DEL, which offered two options to disconnect and terminate distribution charges permanently:

- Option 1: Immediate termination with a PILON of $ 13,073.45 ($ 5,112.24 for transmission and $ 7,338.66 for distribution, plus $ 622.55 Goods and Services Tax); or
- Option 2: No cost with a 7-month notice period. The service would continue to bill on a monthly minimum demand of 220 kW until the notice period expires.

Both the ROM and the termination of service proposal required DEL to indicate its acceptance of an option by providing a signature. DEL did not sign either.

In September 2016, ENMAX notified Fortis and EPCOR Energy that it was deselecting the site because it had moved or would be moving to another site. Fortis reported that this was Fortis' first notice that DEL had reportedly vacated the site. On October 3, 2016, the site was dropped by ENMAX and returned to EPCOR Energy (the regulated rate provider). On October 14, 2016, EPCOR Energy sent Fortis a request to de-energize the site. DEL's service was disconnected on October 17, 2016.

The Complaint

DEL's complaint requested relief from the application of the PILON provisions contained in Fortis' T&Cs. Under the T&Cs, a PILON is charged if a customer gives less than the required notice to reduce demand or to terminate service.

Applicability of Fortis' T&Cs

The AUC first considered whether Fortis' T&Cs, including the PILON provisions, applied to DEL. For the reasons summarized below, the AUC found that the T&Cs, including the PILON provisions, applied to DEL.

The AUC explained that to determine that question, it considered the applicable statutory framework that applied to Fortis' AUC approved tariff. The AUC explained that:

(a) The *Electric Utilities Act* ("*EUA*") and its regulations establish a comprehensive regulatory scheme governing the electricity market and the provision of electricity in Alberta;

(b) As an owner of an electric distribution system under the *EUA*, Fortis had a duty to provide electric distribution service under Section 105 of the *EUA*;

(c) in return, Fortis may recover its prudent costs from eligible customers in accordance with an AUC approved tariff; and

(d) the AUC approved the T&Cs, including the PILON provisions at issue, in Decision 2014-018.

The AUC rejected DEL's arguments that the PILON provisions did not apply because its "original contract" did not contain a PILON provision and that an amendment to that original agreement would require the consent of both parties.

The AUC noted its previous holdings that the terms and conditions between a public utility and its customers are not voluntary contracts, but "legally imposed regulations that bind the utility to provide a service at just and reasonable rates to all who require and demand them."

The AUC found that consistent with the statutory scheme and the principles of public utilities law above, the relationship between Fortis and its customers results from legislative regulation and is not a voluntary one. Therefore, explicit consent from individual customers to changes to terms and conditions of service was not required.

In this case, the AUC found that DEL was a Fortis customer and therefore subject to the T&Cs, including the PILON provisions. This conclusion was based on its findings that:

(a) DEL began purchasing electricity for its own use in 2000, and continued to purchase electricity until DEL sought to disconnect in late August 2016;

(b) therefore, DEL was Fortis' customer, within the *EUA*'s definition of customer (person purchasing electricity for the person's own use), which Fortis also incorporated by reference into the T&Cs at the time DEL disconnected from the site in 2016; and

(c) by operation of the legislative framework and principles of public utilities law, the agreement between DEL and Fortis was therefore governed, in part, by the T&Cs.

Applicability of PILON Charges

The AUC explained that the current PILON provisions were approved through a formal regulatory process in Decision 2014-018. As such, application of the approved T&Cs should not be viewed as unfair, unreasonable or unforeseen, in the absence of evidence establishing that they were applied in a manner not contemplated in the AUC's original approval.

DEL submitted that when its 15-year contract with Fortis expired on December 31, 2015, TransAlta and Fortis had fully recovered their investment in the service, and therefore no PILON charges were owed to Fortis.

The AUC rejected this argument, finding that PILON charges and a utility's recovery of its initial investment are distinguishable, as had been expressly acknowledged by the AUC in previous decisions considering PILON.

DEL also argued that should the AUC determine that PILON charges are due to Fortis, the transmission portion of the PILON charges should be waived. However, DEL did not provide a reason for its request to waive the transmission portion of the PILON charges.

The AUC found that there was no basis in this case, in the T&Cs or otherwise, to waive the PILON charges.

For the above reasons, the AUC found that DEL failed to show that the T&Cs were being applied by Fortis in a manner that is unfair, unreasonable, unforeseen or not contemplated in the AUC's original approval.

ATCO Electric Ltd. – 2016 Performance-Based Regulation Capital Tracker True-Up (Decision 22788-D01-2018)
PBR Regulation – Capital Tracker True-up

In this decision, the AUC considered ATCO Electric Ltd.'s ("ATCO Electric") 2016 capital tracker true-up.

AUC Determinations

The AUC made the following determinations:

- The actual scope, level, timing and actual costs of each of the projects or programs included in the 2016 true-up were prudent, subject to the removal of the Fort McMurray North Service Building Project capital additions and Commission directions with respect to the Buildings, Structures and Leasehold Improvements Program.
- Because of the removal of the Fort McMurray North Service Building Project capital additions and AUC directions with respect to the Buildings, Structures and Leasehold Improvements Program, a reassessment of whether the capital tracker projects or programs included in the 2016 true-up satisfied the accounting test requirement of Criterion 1 was required.
- The previously approved capital tracker projects or programs included in the 2016 true-up continued to meet the requirements of Criterion 2.
- Because of the removal of the Fort McMurray North Service Building Project capital additions and Commission directions with respect to the Buildings, Structures and Leasehold Improvements Program, a reassessment of whether the capital tracker projects or programs included in the 2016 true-up satisfied the two-tiered materiality test requirement of Criterion 3 was required.

Based on the following determinations, the AUC found that it could not make a determination as to whether the projects or programs included in the 2016 true-up satisfied the project assessment requirement of Criterion 1 (defined below) and materiality requirement under Criterion 3 (defined below). The AUC directed ATCO Electric to revise its accounting test for 2016 in a compliance filing to this decision.

The AUC's findings and directions regarding the Fort McMurray North Service Building Project are summarized below.

Eligibility for Capital Tracker Treatment

Projects or programs are eligible for capital tracker treatment, provided that they meet the following three criteria:

(a) The project must be outside the normal course of on-going operations ("Criterion 1");

(b) Ordinarily, the project must be for replacement of existing capital assets, or the project must be required by an external party ("Criterion 2"); and

(c) The project must have a material effect on the company's finances ("Criterion 3").

Criterion 1: Project Assessment and Accounting Test

Criterion 1 requires a two-stage assessment of each project or program for which capital tracker treatment is requested.

At the first stage (project assessment), an applicant must demonstrate that:

(a) the project is required to provide utility service at adequate levels; and, if so,

(b) the scope, level and timing of the project are prudent, and the forecast or actual costs of the project are reasonable.

At the second stage, an applicant must demonstrate the absence of double-counting (the "Accounting Test"). The Accounting Test requires an applicant to demonstrate that the associated revenue provided by the PBR formula will be insufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the program or project in question.

Criterion 2: Replacement/Externally Requested Project

With respect to Criterion 2, a growth-related project will generally qualify where an applicant demonstrates that customer contributions and incremental revenues are insufficient to offset the project's cost.

Criterion 3: Materiality Test

To assess whether a proposed capital tracker has a material effect on a company's finances, an applicant must satisfy the two-part Criterion 3 materiality threshold, namely, that:

(a) each individual project affects the revenue requirement by four basis points; and

(b) on an aggregate level, all proposed capital trackers must have a total impact on the revenue requirement of 40 basis points.

Criterion 1 Applied

Project assessment under Criterion 1 – the project must be outside of the normal course of the company's ongoing operations

The AUC evaluated ATCO Electric's programs or projects included in the 2016 true-up against the second part of the project assessment requirements of Criterion 1, which is whether the actual scope, level, timing and costs of the project were prudent.

The AUC found that the actual scope, level, timing and actual costs of each of the projects or programs included in the 2016 true-up were prudent, subject to the removal of the Fort McMurray North Service Building Project.

The AUC explained that the Buildings, Structures and Leasehold Improvements Program is an annual recurring program involving the procurement of office and garage space, furniture, warehouse and equipment storage facilities, as well as renovations and improvements required for the continuing operation of owned and leased facilities.

Table: Buildings, Structures and Leasehold Improvements Program

Project description	Capital additions	
	2016 approved forecast	2016 actual
	($ million)	
B.1 – Miscellaneous Buildings, Structures and Leaseholds (including Office Furniture)	2.1	0.7
B.2 – Drumheller Service Building	0	0.8
B.5 – Fort McMurray North Service Building	0	20.2
Total	2.1	21.7

The AUC explained that the Fort McMurray North Service Centre (the "North Service Centre") was a new 20,774 square foot building in Fort McMurray, consisting of 15,974 square feet of office space and 4,800 square feet of shop space. In the application, ATCO Electric applied for capital tracker treatment for the north service centre for 2016 with actual capital additions of $20.2 million, with expecting trailing costs of $0.6 million in 2017. ATCO Electric had forecast capital additions of $21.1 million in its 2016-2017 capital tracker forecast application.

The need and scope of the project were approved in Decision 20555-D01-2016 on a forecast basis. In this decision, under the project assessment requirement of Criterion 1, the AUC considered whether the north service centre project was required in 2016 to provide utility service at adequate levels and, if so, whether the actual costs were prudently incurred. Specifically, the AUC considered whether it was necessary to relocate employees to the north service centre in 2016, in order to maintain utility service quality.

The AUC noted that:

(a) in September 2016, before the north service centre was ready for occupancy in October 2016, ATCO Electric had 82 employees requiring office space in Fort McMurray; and

(b) 56 employees were located in the south service centre, and 26 were located in the portable units.

The AUC found that:

(a) given the availability of space at the south service centre, it was not necessary for ATCO Electric to move employees from the south service centre to the North Service Centre in order to maintain service quality in 2016; and

(b) given the availability of the office space in the portable units and the fact that utilities at that site were not disconnected until 2017, there was no requirement to relocate employees from these units in order to maintain service quality in 2016.

The AUC concluded that the North Service Centre project did not meet the project assessment requirement of Criterion 1. Therefore, the AUC denied capital tracker treatment as requested by ATCO Electric for 2016.

The AUC directed ATCO Electric to remove the 2016 capital additions related to the Fort McMurray North Service Building Project from the Buildings, Structures and Leasehold Improvements Program in its compliance filing.