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DECISIONS

ENERGY REGULATORY REPORT

Regulatory Law Chambers *is a Calgary-based boutique law firm dedicated to excellence in energy regulatory matters. We have expertise in oil and gas, electricity, including renewable energies and commercial matters, tolls and tariff, compliance and environmental related matters. We frequently represent clients in proceedings before the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission ("AUC"), the National Energy Board ("NEB"), all levels of the Courts, and in energy related arbitrations and mediations.* ***Our advice is practical and strategic. Our advocacy is effective.***

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.

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FEDERAL COURT OF APPEAL

Tsleil-Waututh Nation v. Canada (Attorney General), 2018 FCA 153
Trans Mountain Expansion Project -Pipeline - Aboriginal Consultation - Environmental Assessment

Introduction

In this decision, the Federal Court of Appeal ("FCA") considered consolidated applications for judicial review by Aboriginal groups and two cities (Vancouver and Burnaby) (the "Applicants"), seeking to quash decisions of the NEB and Governor in Council ("GiC") approving the Trans Mountain Expansion Project (the "Project"), namely:

(a) the NEB decision report dated May 19, 2016 (the "NEB Report"); and

(b) the Order in Council, PC 2016-1069, dated November 29, 2016, made by the GiC (the "Order in Council").

The Applicants challenged the Order in Council on two principal grounds: (1) the NEB's process and findings were so flawed that the GiC could not reasonably rely on the NEB Report; and (2) Canada failed to fulfill the duty to consult owed to Indigenous peoples.

The FCA allowed the applications for judicial review of the Order in Council, quashed the Order in Council and remitted the matter to the GiC for redetermination.

The Project

The FCA noted that the Project would increase the number of tankers loaded at the Westridge Marine Terminal in the City of Burnaby from approximately 5 to 34 tankers per month. The Project would increase the overall capacity of Trans Mountain's existing pipeline system from 300,000 barrels per day to 890,000 barrels per day.

Summary of Conclusions

With respect to the GiC's reliance on the NEB Report, the FCA's significant findings included the following:

(a) the NEB unjustifiably defined the scope of the Project under review not to include Project-related tanker traffic;

(b) the unjustified exclusion of marine shipping from the scope of the Project led to successive, unacceptable deficiencies in the NEB's report and recommendations; and

(c) as a result, the GiC could not rely on the NEB's report and recommendations when assessing the Project's environmental effects and the overall public interest.

With respect to the adequacy of Crown consultation with Indigenous groups, the FCA concluded that Canada's duty to consult was not adequately discharged. The FCA's findings regarding the adequacy of Canada's consultation included the following:

(a) Canada acted in good faith and selected an appropriate consultation framework.

(b) However, Canada failed to discharge its duty during the last stage of the consultation process (referred to as Phase III) to engage, dialogue meaningfully, and grapple with the real concerns of the Indigenous applicants, so as to explore possible accommodation of Indigenous groups' concerns.

Legislative Scheme

The FCA set out the following legislative scheme governing the NEB's consideration of the Project and the GiC's Order in Council decision, which relied on findings and recommendations from the NEB Report.

Requirements of the National Energy Board Act

- The NEB must prepare a report setting out its recommendation as to whether a certificate of public convenience and necessity ("CPCN") should be granted, including the NEB's recommended conditions of approval [*National Energy Board Act* ("*NEBA*"), section 52(1)].

- The NEB's recommendation is to be based on "all considerations that appear to it to be directly related to the pipeline and to be relevant" and the NEB may consider the enumerated factors, including "any public interest factor that in the Board's opinion may be affected by the issuance of the certificate or the dismissal of the application" [*NEBA*, section 52(2)].

- For an application relating to a "designated project," as defined in section 2 of *the Canadian Environmental Assessment Act, 2012*, ("*CEAA, 2012*"), the NEB's report must set out the NEB's environmental assessment of the Project [*NEBA*, section 52(3)].

Requirements of the Canadian Environmental Assessment Act, 2012

- Because the Project included pipeline segments longer than 40 kilometres, it was a designated project ("DP") under the *CEAA, 2012*.

- As a result, the NEB was required, as the designated authority under *CEAA, 2012*, section 15(b), to conduct an environmental assessment as part of its consideration of the Project.

- Section 19(1) of the *CEAA, 2012*, requires the NEB to consider the enumerated factors listed in that section, including the following:

  - the environmental effects and any cumulative environmental effects likely to result from the DP;

  - technically and economically feasible mitigation measures; and

  - alternative technically and economically feasible means of carrying out the DP and the environmental effects of any such alternative means.

- The NEB must make recommendations to the GiC with respect to its decision about the existence of significant adverse environmental effects and whether those effects can be justified in the circumstances [*CEAA, 2012,* section 29(1)].

Consideration by GiC of NEB Report

- Once in receipt of the NEB Report prepared in accordance with the requirements of the *NEBA* and the *CEAA, 2012*, the GiC may make one of the following three decisions:

  - direct the NEB to issue a CPCN for a pipeline and make the CPCN subject to the terms and conditions set out in the NEB Report [*NEBA*, section 54(1)(a)];

  - direct the NEB to dismiss the application for a CPCN [*NEBA,* section 54(1)(b)]; or

  - refer the recommendation set out in the report (including recommended conditions) back to the NEB for reconsideration [*NEBA,* section 53(1) & (2)].

- With respect to the environmental assessment prepared by the NEB, pursuant to section 31(1) of the *CEAA, 2012*, the GiC may decide, taking into account the implementation of any recommended mitigation measures specified in the report, that the DP: (i) is not likely to cause significant adverse environmental effects; (ii) is likely to cause significant adverse environmental effects that can be justified in the circumstances; or (iii) is likely to cause significant adverse environmental effects that cannot be justified in the circumstances.

The NEB Report

On May 19, 2016, the NEB issued its report which recommended approval of the Project. The recommendation was based on findings, including the following:

- With the implementation of Trans Mountain's environmental protection procedures and mitigation measures, and the NEB's recommended conditions, the Project was not likely to cause significant adverse environmental effects.

- Effects from Project-related increased tanker traffic would contribute to the total cumulative effects on the endangered Southern resident killer whales, and would further impede the recovery of that species.

- The likelihood of a spill from the Project or from a Project-related tanker would be very low in light of the mitigation and safety measures to be implemented. However, the consequences of large spills could be high.

- The NEB's recommendation and decisions with respect to the Project were consistent with section 35(1) of the *Constitution Act, 1982*.

The GiC Decision

On November 29, 2016, the GiC issued the Order in Council, accepting the NEB's recommendation that the Project be approved and directing the NEB to issue a CPCN to Trans Mountain. The FCA noted two recitals in the Order in Council relevant to these applications:

(a) the GiC stated its satisfaction that the consultation process was consistent with the honour of the Crown and the Aboriginal concerns and interests had been appropriately accommodated; and

(b) the GiC accepted the NEB's recommendation that the Project was required by present and future public convenience and necessity and that it would not likely cause significant adverse environmental effects.

Is the NEB Report Amenable to Judicial Review?

The FCA concluded that applications for judicial review do not lie against NEB reports made pursuant to section 52 of the *NEBA* recommending whether a CPCN should be issued for a pipeline (citing *Nation v. Canada*, 2016 FCA 187 at para. 125 ("*Gitxaala*")). Under the operative legislative scheme, only the GiC actually decides anything. Any deficiency in an NEB's report, including its environmental assessment, is to be considered by the GiC and not the Court.

In this case, the City of Vancouver was the only applicant to have challenged the NEB Report, but not the Order in Council. The FCA determined that, as a result, the City of Vancouver was precluded from challenging the Order in Council.

Should the GiC Decision Be Set Aside for Relying on Deficient Recommendations from the NEB Report?

Standard of Review

The FCA concluded that the reasonableness standard of review applied to the question of whether the GiC and the responsible authorities had respected the legislative requirements before determining whether the project at issue was justified despite its adverse environmental effects (citing *Gitxaal*).

In this case, the FCA explained that the reasonableness standard of review required the Court to be satisfied that the GiC's decision was lawful, reasonable, and constitutionally valid. To be lawful and reasonable, the GiC must comply with the purview and rationale of the legislative scheme.

The GiC Erred by Relying on the NEB Report as a Proper Condition Precedent to its Decision

The FCA held that the NEB Report was so flawed that it was unreasonable for the GiC to rely on it in making its decision.

The FCA found that the NEB erred by unjustifiably excluding Project-related marine shipping from the Project's definition, and therefore not including such impacts from its environmental assessment under the *CEAA, 2012*. While the Board's assessment of Project-related shipping was adequate for the purpose of informing the GiC about the effects of such shipping on the Southern resident killer whale, the NEB Report was also sufficient to put GiC on notice that the NEB had unjustifiably excluded Project-related shipping from the Project's definition.

The FCA found that it was this exclusion that permitted the NEB to conclude that:

(a) section 79 of the *Species at Risk Act* did not apply to its consideration of the effects of Project-related marine shipping; and

(b) notwithstanding its conclusion that the operation of Project-related marine vessels is likely to result in significant adverse effects to the Southern resident killer whale, the Project (as defined by the Board) was not likely to cause significant adverse environmental effects.

The FCA found that the material deficiencies in the NEB Report did not permit the GiC to make an informed decision about the public interest and whether the Project was likely to cause significant adverse environmental effects, as the legislation required.

Should the GiC Decision Be Set Aside on the Ground that Canada Failed to Consult Adequately?

Standard of Review

Citing *Haida Nation v. British Columbia (Minister of Forests)*, 2004 SCC 73, at paras 61-63, the FCA found that:

(a) the existence and extent of the duty to consult are legal questions reviewable on the standard of correctness, and

(b) the adequacy of the consultation is a question of mixed fact and law which is reviewable on the standard of reasonableness.

In this case, only the question of the adequacy of consultation was subject to dispute, reviewable by the FCA on the reasonableness standard.

Adequacy of the Consultation Process

The FCA found that the consultation framework selected by Canada was reasonable and sufficient. If Canada had properly executed it, it would have discharged its duty to consult. In finding the consultation framework selected to be reasonable, the FCA considered the following:

- the Indigenous applicants were given early notice of the Project, the NEB's hearing process, the framework of the consultation process and Canada's intention to rely on the NEB process, to the extent possible, to discharge Canada's duty to consult;
- participant funding was provided to the Indigenous applicants;
- the NEB process permitted Indigenous applicants to provide written evidence and oral traditional

evidence, to question both Trans Mountain and the federal government interveners through information requests and to make written and oral closing submissions;

- the regulatory framework permitted the NEB to impose conditions that were capable of mitigating risks posed by the Project to the rights and title of the Indigenous applicants; and

- after the NEB hearing record closed and before the GiC decision, Canada provided a further consultation phase, Phase III, designed to enable Canada to deal with concerns not addressed by the hearing, the NEB's proposed conditions, and Trans Mountain's commitments.

Adequacy of Execution of Consultation Process

The FCA found that in the execution of the consultation process, Canada failed to discharge its duty to consult as a result of following an unreasonable consultation process that fell well short of the required mark. While Canada is not to be held to a standard of perfection, the flaws summarized below thwarted meaningful, two-way dialogue. The FCA found that Canada's consultation was flawed and inadequate based on the following:

- Missing from the consultation was a genuine and sustained effort to pursue meaningful, two-way dialogue. The FCA found that in response to outstanding concerns raised by Indigenous applicants during Phase III, Canada's consultation team provided very few responses. When a response was provided, it was brief and did not further two-way dialogue. Too often, in the FCA's view, the response was that the consultation team would put the concerns before the decision-makers for consideration.

- Missing from Canada's consultation team was someone representing Canada who could engage interactively. Someone with the confidence of Cabinet who could discuss, at least in principle, required accommodation measures, possible flaws in the NEB's process, findings and recommendations and how those flaws could be addressed.

- The inadequacies of the consultation process also flowed from Canada's unwillingness to meaningfully discuss and consider possible flaws in the NEB's findings and recommendations and Canada's erroneous view that it could not supplement or impose additional conditions on Trans Mountain.

The FCA found that the above three systemic limitations were then exacerbated by Canada's late disclosure of its assessment that the Project did not have a high level of impact on the exercise of the applicants' "Aboriginal Interests" and its related failure to provide more time to respond so that all Indigenous groups could respond.

<u>Remedy</u>

The FCA quashed the Order in Council, rendering the CPCN approving the construction and operation of the Project a nullity. The FCA ordered that that issue of Project approval be remitted to the GiC for prompt redetermination.

In that redetermination, the GiC must refer the NEB's recommendations and its terms and conditions back to the NEB for reconsideration.

Specifically, the NEB must reconsider on a principled basis whether Project-related shipping is incidental to the Project, the application of section 79 of the *Species at Risk Act* to Project-related shipping, the NEB's environmental assessment of the Project in light of the Project's definition, the NEB's recommendation under subsection 29(1) of the *CEAA, 2012* and any other matter the GiC should consider appropriate.

Further, Canada must re-do its Phase III consultation. Only after that consultation is completed and any accommodation made can the Project be put before the GiC for approval.

<u>Disposition</u>

The FCA allowed the applications for judicial review of the Order in Council, quashed the Order in Council and remitted the matter to the GiC for redetermination.

ALBERTA ENERGY REGULATOR

AER Bulletin: Coordinated Submission of Related Applications for Oil Sands Exploration Activities (Bulletin 2018-21)
Oil Sands Exploration - Bundling Applications

In this bulletin, the AER announced changes to its processing of oil sands exploration ("OSE") applications by bundling applications submitted by proponents.

The AER will now process OSE applications under section 20(1) of the *Public Lands Act* together with related *Directive 056: Energy Development Applications and Schedules* ("Directive 056") well licence applications.

In the AER's view, a bundled application process will benefit stakeholders by making the process more efficient and easier to navigate, and the project will be clearly understood as a single project rather than as individual pieces.

AER Bulletin: Optional Process for Submitting Fluid Disposal Applications (Bulletin 2018-22)
Optional Application Process - Disposal Wells

In this bulletin, the AER announced that it would allow operators to apply to dispose of Class I, II, or III fluids in an underground formation through a well before the disposal well is drilled. The AER explained that this optional two-step application process could provide operators with information about approval conditions before an investment is made in drilling the disposal well and constructing associated surface facilities. Operators choosing not to use this application process must use the regular fluid disposal application process under *Directive 065: Resources Applications for Oil and Gas Reservoirs*, which requires the disposal well to be drilled before application.

All fluid disposal applications submitted under this process will still be reviewed using the same assessment criteria as applications submitted under the regular Directive 065 application process, and all other existing rules and regulations will apply.

ALBERTA UTILITIES COMMISSION

2018 Generic Cost of Capital (Decision 22570-D01-2018)

Rate - Electricity/Gas - Distribution/Transmission - Deemed Cost of Capital - Debt/Equity Ratio - Return on Equity - Capital Markets

In this decision, the AUC determined the return on equity ("ROE") on a final basis for the years 2018, 2019 and 2020 that applies uniformly to the utilities listed below:

- AltaGas Utilities Inc. ("AltaGas");
- AltaLink Management Ltd. ("AltaLink");
- ATCO Electric Ltd. ("ATCO Electric");
- ATCO Gas & Pipelines Ltd. ("ATCO Pipelines");
- ENMAX Power Corporation ("ENMAX");
- EPCOR Distribution & Transmission Inc. ("EPCOR");
- FortisAlberta Inc. ("FortisAlberta");
- City of Lethbridge ("Lethbridge");
- City of Red Deer ("Red Deer"); and
- TransAlta Corporation ("TransAlta"),

(collectively, the "Affected Utilities").

The AUC set out the approved deemed equity ratios (also referred to as capital structure) that apply to the Affected Utilities.

The AUC determined that a fair generic ROE for the Affected Utilities was 8.5 per cent for 2018, 2019, and 2020.

The approved final deemed equity ratios for 2018, 2019 and 2020 for the Affected Utilities are set out in the table below:

Table: AUC Approved Deemed Equity Ratios

Company	2018-2020 Approved Equity Ratio	Previously Approved in 2016 GCC Decisions	Change
Electricity and Natural Gas Transmission			
AltaLink	37	37	0
ATCO Electric (Transmission)	37	37	0
ATCO Pipelines	37	37	0
ENMAX (Transmission)	37	36	+1
EPCOR (Transmission)	37	37	0
Lethbridge	37	37	0
Red Deer	37	37	0
TransAlta	37	37	0
Electricity and Natural Gas Transmission			
AltaGas	39	41	-2
ATCO Electric (Distribution)	37	37	0
ATCO Gas	37	37	0
ENMAX (Distribution)	37	36	+1
EPCOR (Distribution)	37	37	0
FortisAlberta	37	37	0

Additionally, the AUC considered whether to direct the Affected Utilities to adopt a uniform income tax treatment methodology.

Fair Return Standard

The *Public Utilities Act* and *Gas Utilities* Act require that, in fixing just and reasonable rates, the AUC fix a fair return on a public utility owner's investment (i.e. rate base).

The AUC is required to exercise its discretion in determining a total return for each utility that provides a reasonable opportunity to earn a fair return on invested capital while ensuring that rates are just and reasonable.

The AUC and its predecessors have accepted and considered the following well-established three factors when setting a fair return:

(a) comparable investments;

(b) capital attraction; and

(c) financial integrity.

AUC Approach to Setting Allowed ROE and Deemed Equity Ratios

The AUC explained its approach as establishing an ROE that applies uniformly to the Affected Utilities. However, to account for variation in business risk faced by individual utilities, the AUC may approve deemed equity ratios on an individual basis.

In making its determination of a fair ROE, the AUC considered changes in the global and Canadian capital market conditions since the previous AUC Decision 20622-D01-2016 regarding Generic Cost of Capital, which (the "2016 GCC Decision") set out the AUC approved ROE and deemed equity ratios for the Affected Utilities for the years 2016, 2017, and 2018.

The AUC went on to examine the relationship between capital structure (i.e. debt/equity ratio) and ROE, with respect to establishing a fair ROE for the Affected Utilities.

Estimating Required ROE

Generally, the cost of equity to a firm is the return that investors require to make on equity investment in that firm. The approved cost of equity (i.e. ROE) in the period is a point estimator of investor return expectations that reflects investors' return requirements over the long run.

The AUC received expert written evidence and testimony from a variety of experts sponsored by the Affected Utilities and interveners. The experts provided evidence on the current financial environment and the results of a number of models and opinions to assist the AUC in determining a fair ROE.

Capital Markets and Changes Since 2016

The experts presented evidence regarding changes in macroeconomic factors since the 2016 GCC Decision, including:

(a) globally positive economic growth;

(b) expectations that Canada and Alberta would experience continued moderate but solid GDP growth; and

(c) a rise in global oil prices.

The AUC found that the global economic and Canadian capital market conditions improved since the 2016 GCC Decision. In particular, the AUC noted that there was global and national economic growth, reduced market volatility, a modest increase in the 30-year Government of Canada bond yield and a compression in credit spreads.

The AUC found that the upward pressure on ROE associated with certain developments in capital markets was offset by the downward pressure associated with other factors (e.g. decrease in credit spreads). On balance, considering the macroeconomic factors, the AUC considered that the approved ROE for 2018 should be at or near that set in the 2016 GCC Decision.

With respect to future expectations for global economic and Canadian capital market conditions, the AUC noted the expectations of diminishing national GDP growth rates, moderately higher inflation, increasing short-term interest rates, a flattening yield curve, but uncertain long-term interest rates and market uncertainty with respect to international trade.

Modelling a Fair ROE

Capital Asset Pricing Model

The capital asset pricing model ("CAPM") approach is broadly based on the principle that investors' compensation for the use of their capital must recognize two factors: their foregone time value of money, and any risk attendant in the investment.

In this way, CAPM estimates a fair rate of return by calculating the expected required return for a security as the rate of return on a risk-free security plus a risk premium in accordance with the formula:

$$R_e = R_f + \beta[E(R_m) - R_f],$$

Where:

- R_e is the required return for investors to invest;

- R_f is the risk-free rate, representing the return of a risk-free security;
- $[E(R_m) - R_f]$ is the market equity risk premium ("MERP"), representing the premium an investor requires to address the risk that an expected return on the subject security will not be achieved during the period; and
- (β) is a measure of how sensitive the subject security's required return is relative to changes in overall market returns (R_m), usually derived from the statistical relationship between historical returns for a given security and the returns of the overall capital market during the same time period.

Risk-free Rate (R_f)

The AUC found that the prevailing yield on long-term Government of Canada bonds of 2.3 percent represented a reasonable estimate of the risk-free rate (R_f) over the 2018-2020 term.

MERP ($E(R_m) - R_f$)

The AUC found that the evidence suggested a MERP above 6.89 percent.

In determining a reasonable MERP, the AUC considered the historical Canadian rates and the regression method results produced by Mr. Hevert (the expert witness co-sponsored by EPCOR and FortisAlberta).

The results of Mr. Hevert's regression model were 6.89 percent using a risk-free rate of 2.37 percent. The AUC considered that this suggested a MERP above 6.89 percent, given the AUC's finding that 2.3 percent was a reasonable estimate for R_f.

Beta (β)

Beta is a statistical measure describing the relationship of a given security's return with that of the equity market. The AUC affirmed its previous findings that the appropriate beta to use is one that reasonably represents the relative risk of stand-alone Canadian utilities. The AUC determined it would continue to consider both weekly and monthly based beta estimates in determining reasonable beta estimates. The AUC found that a reasonable range of betas was 0.45 to 0.95.

Resulting CAPM Estimate for ROE (R_e)

The AUC found that 7.90 percent was a reasonable point estimate for the CAPM model, which it would consider in establishing the ROE fair return for the Affected Utilities. This estimate was based on using the risk-free rate of 2.60 percent, a MERP of 7.00 percent, an average beta of 0.686 and allowing for a flotation allowance of 0.50 percent, which resulted in an estimate ROE of 7.90 percent.

Given the uncertainty regarding the magnitude and timing of potential changes in the risk-free rate, the AUC considered the estimate of 2.60 percent for $\mathrm{R_f}$ recommended by Dr. Cleary to be reasonable.

The Affected Utilities presented a large number of CAPM estimates by varying input parameters for each of the risk-free rate R_f, beta (β), and MERP $[E(R_m) - R_f]$. The AUC noted that the wide range of CAPM estimates (5.48-11.40%) was not surprising, given its determination that the use of weekly and monthly based beta estimates and use of adjusted and unadjusted betas in the CAPM model, were acceptable.

Discounted Cash Flow Model

The discounted cash flow ("DCF") approach estimates the cost of a company's common equity based on the current dividend yield of the company's shares plus the expected future dividend growth rate. The DCF method calculates ROE as the rate of return that equates the present value of the expected dividend income stream to the current share price.

The AUC found that 8.79 percent was a reasonable point estimate for the multi-stage DCF method.

The witnesses presented the AUC with ROE estimates determined using both single-stage and multi-stage DCF models. Consistent with its determinations in prior GCC decisions, the AUC would not accept, in a single-stage DCF model that used growth rates that exceeded estimates of the nominal long-term GDP growth rate for the economy. The AUC found that the Affected Utilities were essentially monopolies in mature markets and, because of this, the use of long-term growth in excess of the long-term growth of GDP was unreasonable.

Flotation Allowance

The AUC found that a flotation allowance of 0.50 percent continued to be reasonable and would accept this adjustment to the ROE results obtained through CAPM, DCF, or risk premium models.

The AUC affirmed its findings from previous decisions that a flotation allowance was normally included in the allowed return to account for administrative costs and equity issuance costs, any impact of under-pricing a new issue, and the potential for dilution.

Conclusions on ROE

The AUC was not persuaded by the parties' evidence, including empirical modelling, to depart from the current approved ROE of 8.50 percent. As a result, the AUC approved 8.50 percent as the ROE on a final basis for the Affected Utilities for 2018, 2019, and 2020.

The AUC noted that:

(a) in the 2016 GCC decision it awarded an ROE of 8.3 percent for 2016 and an ROE of 8.5 percent for 2017; and

(b) it correspondence initiating this proceeding set out that it would consider, among other things, whether a change in the approved ROE established in the 2016 GCOC decision was warranted.

The AUC found that:

(a) no party focused on the changes since 2016, and no party explained why the increase of 20 bps for 2017 was either still warranted or insufficient on a going-forward basis;

(b) if there had been some upward pressure on ROE since the 2016 GCOC proceeding, part of that pressure had already been accounted for in the 20 bps increase in ROE awarded in 2017;

(c) the 20 bps increase awarded in 2017 was premised on the AUC's finding that economic conditions were generally expected to improve in 2017, including an expected increase in interest rates and utility bond yields;

(d) the expected increase in 30-year GOC bond yields arguably signalled an increase in approved ROE for 2018 to 2020;

(e) however, the expected increase in ROE had been mitigated at least somewhat by the tightening of credit spreads;

(f) this resulted in utility bonds being effectively unchanged since the 2016 GCC proceeding, contrary to what the Commission considered would occur in Decision 20622-D01-2016; and

(g) any additional ROE required by utility investors was largely accounted for in the 2017 adjustment approved in the 2016 GCOC decision.

Returning to a Formula-based Approach to Establishing ROE

The AUC indicated its intention to explore the possibility of returning to a formula-based approach to cost of capital matters and that it would be initiating a proceeding to explore available options. The AUC considered that returning to an annual adjustment/generic formula approach to ROE might be reasonable and improve administrative efficiency.

The AUC also considered that the issues raised in this and previous GCC decisions in relation to the approaches to estimating ROE and the varied inputs and results might be remedied by adopting a formula-based approach in a future proceeding.

Deemed Equity Ratios

The AUC found that no change was required to the deemed equity ratio set out in the 2016 GCC decision, with the exception of the deemed equity ratio for ENMAX (Transmission and Distribution) and the deemed equity ratio for AltaGas.

Credit Metrics

Consistent with past GCC decisions, the AUC awarded common equity ratios that, on a stand-alone basis, were consistent with credit ratios in the A category.

The AUC considered a number of credit metrics to determine an equity ratio consistent with a capital structure that allows a utility to maintain A category credit rating. In reaching its determination, the AUC held that the funds for operation ("FFO")/debt ratio is the most important metric in the assessment of a regulated utility's creditworthiness.

Using the approved ROE and deemed equity ratio, the AUC noted that the credit metric analysis showed FFO interest coverage ratios of 3.9 and 3.3 for the distribution and transmission utilities, respectively. The credit metric analysis also showed FFO/debt ratios of 13.8 and 11.1 per cent for the distribution and transmission utilities, respectively.

The AUC considered evidence regarding the benchmarks associated with certain credit metrics used by various credit rating agencies. The AUC agreed that formal credit metrics should be considered in the assessment of deemed equity ratios. The Alberta regulatory advantage is currently rated by S&P as "strong" with a downward trend of "negative." This was the same rating that was in place during the 2016 GCC Decision. The AUC found there was no significant increase in generic business risk for the Affected Utilities since the 2016 GCC Decision.

Equity Ratio Adjustments for Income Tax Exempt or Non-Taxable Utilities

The AUC found that a 200 bps adder to the deemed equity ratio for the income tax exempt utilities was not warranted. The AUC held that even without a premium for utilities not paying income tax, such utilities would still qualify for credit ratings in the A range with a deemed equity ratio of 37 per cent. The AUC held that the use of the A-range credit rating target is a factor that respects the financial integrity, capital attraction and comparability aspects of the fair return standards.

Deemed Equity Ratio for AltaGas Utilities Inc.

The AUC approved for AltaGas a deemed equity ratio of 39 per cent for 2018, 2019, and 2020.

Because AltaGas is unable to access lower cost debt that is associated with an A-range credit rating, coupled with the uncertainty of its future debt costs, the AUC considered that AltaGas's deemed equity ratio should be lowered from the 41 percent set in the 2016 GCC Decision. Otherwise, consumers would bear the costs of both the additional cost of the increase in equity thickness and the cost of paying interest rates above those for an A-rated utility.

The AUC accepted that the business risk of AltaGas is greater than that of the other utilities in Alberta. This, on its own, suggested a higher deemed equity ratio for AltaGas should be greater than the deemed equity ratio to achieve A-range credit ratings. However, the AUC determined that the inability of AltaGas to raise debt at A-range credit rating levels, and the uncertainty with respect to AltaGas' future debt costs, warranted a downward adjustment to the deemed equity ratio of AltaGas, relative to that approved for the other utilities.

Deemed Equity Ratio for ENMAX

The AUC acknowledged the submission that ENMAX was committed to maintaining an actual equity ratio that was consistent with its deemed equity ratio. In reviewing the 2016 Rule 005 reports for ENMAX Transmission and ENMAX Distribution, the AUC noted that the actual year-end ratio for both was 37 per cent. The considered that there was nothing to suggest that ENMAX should be considered lower risk than the other utilities in Alberta. Therefore, the AUC found that the deemed equity ratio for ENMAX should be the same as the other Affected Utilities, with the exception of AltaGas.

<u>Income Tax</u>

In this decision, the AUC also considered whether a uniform tax methodology should be applied uniformly to the Affected Utilities, or whether different methodologies should be used under different circumstances. Parties focused on two common income tax methods: the flow-through method and the future income tax ("FIT") method.

The AUC found that the use of the flow-through method was acceptable, and should continue to be used as the default method. The AUC rejected the recommendation from the CCA to require every utility to uniformly adopt the FIT method, given its findings that the adoption of the FIT method would result in significant cost implications for customers.

An individual utility may still apply to the AUC for approval to adopt the FIT method in a future rate-related proceeding. The onus will be on such an applicant to satisfy the AUC that the specific circumstances warrant a change to the FIT method.

Flow-through Method

The flow-through method is analogous to the cash basis of accounting. When using the flow-through method, the forecast income tax is calculated by multiplying the forecast income tax rates by the taxable income. In determining taxable income, non-cash expenses such as depreciation are not deductible. Instead of depreciation, the taxing authorities permit a deduction called capital cost allowance. The AUC approved depreciation rates are generally lower than the capital cost allowance rates set by tax authorities. Consequently, during periods when the monetary value of the capital asset additions of a utility is large, the capital cost allowance deduction is much greater than the non-deductible depreciation expense.

As a result of differences in depreciation and capital cost allowance and the ability to immediately deduct certain costs for income tax purposes, taxable income and income taxes are lower in periods when the utility has capital asset additions of significant monetary value.

FIT Method

The FIT method is analogous to the accrual basis of accounting and consists of two components:

(a) the cash component, being the amount that would have to be paid to the taxing authorities, is determined using the flow-through method described above; and

(b) future income taxes, determined by accounting for all the differences between the non-cash expenses and the income tax deductions.

Because these differences are accounted for, the FIT method recognizes the liability for increased income taxes in future periods, all else being equal. Any FIT balances are also adjusted for changes in future income tax rates.

Requiring Uniform Adoption of FIT Not Warranted

The AUC found that the use of the flow-through method was acceptable, and should continue to be used as the default method.

The AUC noted that all of the taxable utilities had recent substantial capital asset additions. Consequently, the income taxes calculated for the taxable utilities using the flow-through method were lower than if the FIT method had been used.

The AUC considered that transition to the FIT method would reveal significant FIT liabilities and have a resulting impact on rates.

Summary

In this decision, the AUC set out:

(a) the approved ROE of 8.50% applicable to the Affected Utilities for 2018, 2019, and 2020;

(b) the approved deemed equity ratio of 37% applicable to all of the Affected Utilities, with the exception of AltaGas; and

(c) the approved deemed equity ratio of 39% applicable to AltaGas.

Village of Alliance Appeal Pursuant to Section 43 of the Municipal Government Act (Decision 23398-D01-2018)

Rate Structure - Public Utilities

In this decision, the AUC considered an appeal by Mr. Jeremy Huet pursuant to sections 43 of the *Municipal Government Act* ("*MGA*") requesting the AUC disallow certain utility charges imposed by the Village of Alliance (the "Village").

For the reasons summarized below, the AUC found that the Village improperly imposed the tenant, Mr. James Brozny's utility service charges, arrears, and associated penalties against the property owner, Mr. Jeremy Huet. Therefore, the AUC disallowed these charges.

Commissions Jurisdiction Under *MGA* Section 43

Section 43 of the *MGA* states:

> 43(1) A person who uses, receives or pays for a municipal utility service may appeal a service charge, rate or toll made in respect of it to the Alberta Utilities Commission, but may not challenge the public utility rate structure itself.
>
> (2) If the Alberta Utilities Commission is satisfied that the person's service charge, rate or toll
>
> (a) does not conform to the public utility rate structure established by the municipality,
>
> (b) has been improperly imposed, or
>
> (c) is discriminatory,
>
> the Commission may order the charge, rate or toll to be wholly or partly varied, adjusted or disallowed.

Mr. Huet brought the appeal pursuant to sections 43(2)(b) and (c) of the *MGA*. The AUC also considered that Mr. Huet's appeal raised claims that fell under section 43(2)(a) of the *MGA* regarding whether certain charges did not conform with the rate structure established by the Village.

Did the Rates Conform to the Public Utility Rate Structure?

The AUC explained that in assessing an appeal under section 43(2)(a), its role was not to comment on the Village's rate structure itself. Rather, the AUC considered whether a ratepayer, here, Mr. Huet, was being charged according to the rate structure established by the Village.

Were Rates Improperly Imposed?

The AUC explained that in assessing an appeal under section 43(2)(b), it considered the powers and functions of the Village, a municipality, as set out in the *MGA*. The AUC noted that section 43(2)(b) appeals often raised questions about the legality of the utility service charge, rate, or toll.

Were Rates Discriminatory?

In assessing an appeal under section 43(2)(c), the AUC cited its previous holdings that discrimination can arise in two circumstances:

(a) first, when a utility fails to treat all its users equally where no reasonable distinction can be found between those favoured and those not favoured, and

(b) second, when a utility treats all its users equally where differences between users would justify different treatment.

On an appeal under section 43(c) of the *MGA,* the AUC explained that it must assess the rationale or logic underlying the utility service charges applied by the Village to Mr. Huet. In this case, the AUC considered that it had to determine whether Mr. Huet had been placed in the correct rate class, and determine whether reasonable distinctions may exist between customers within a rate class so as to support any inconsistent treatment.

AUC Findings

The AUC considered the appeal raised two distinct issues, namely:

(a) whether the Village improperly imposed the outstanding utility service charges and associated penalties incurred by the tenant on Mr. Huet (the landowner); and

(b) whether the resident infrastructure fee and garbage fee that the Village imposed on Mr. Huet after the property became vacant conformed with the rate structure, was improperly imposed or was discriminatory.

Liability for Tenant's Utility Service Charge Arrears

The AUC found that the Village improperly imposed the occupant, Mr. Brozny's utility service charges, arrears, and associated penalties upon Mr. Huet (the owner), based on the following:

(a) the Village agreed to provide utility service to the tenant, Brozny, at the tenant's request;

(b) *MGA* section 42(2) provides that if a municipality provides a municipal utility service to a site at the request of an occupant who is not the owner of the parcel of land, the charges for the municipal utility service are owed by the occupant and not the owner;

(c) accordingly, pursuant to section 42(2) of the *MGA*, these charges were improperly imposed on Mr. Huet; and

(d) therefore, Mr. Huet was not liable for the outstanding utility service charges and associated penalties incurred by the tenant.

Utility Service Charges Imposed After the Property Vacated by Tenant

The AUC found that Mr. Huet was charged in accordance with the rate structure established by utility Bylaw 2015-01 with respect to the resident infrastructure fee and garbage fee. The AUC accepted that the Village considered Mr. Huet an "absentee resident" (resident within the Village who is absent from their residence for an extended period of time).

The AUC determined that Mr. Huet was placed in the correct rate class and did not find that the resident infrastructure fee charged to Mr. Huet by the Village was discriminatory.

Summary

The AUC found that the Village improperly imposed the tenant's utility service charges, arrears, and associated penalties against Mr. Huet (the owner). Therefore, these costs were disallowed. The AUC ordered the Village to repay Mr. Huet any amount he paid for the tenant, Mr. Brozny's utility service charge arrears and associated penalties.

Town of Coaldale Appeal Pursuant to Section 43 of the Municipal Government Act (Decision 23159-D01-2018)
Rate Structure - Municipal Public Utilities

In this decision, the AUC considered an appeal by Ms. Eleanor Britz, Ms. Nadine Britz, and Mr. Doug Shields (the "Complainants") pursuant to sections 43(2)(a), (b), and (c) of the *Municipal Government Act* ("*MGA*") regarding certain water, drainage, sewer, and waste management service charges imposed by the Town of Coaldale ("Coaldale").

For the reasons summarized below, the AUC found that the water, drainage and sewer service charges disputed in this appeal did not conform to the public utility rate structure established by Coaldale.

The AUC found that the grounds of appeal in relation to waste management service charges were not established and dismissed this part of the appeal.

Background

Coaldale was charging each dwelling unit of the property as if it were individually metered, even though each dwelling unit did not have an individual water meter. Coaldale explained that its policy is to allow multi-residential unit dwellings to have one water meter for multiple units in order to save the property owner from the expense of installing separate water meters for each unit.

Legislative Scheme

The AUC explained that a municipality's rights and responsibilities in providing public utility services are primarily identified in Part 3 ("Special Municipal Powers and Limits on Municipal Powers") of the *MGA*, sections 33 to 44, under the heading "Municipal Public Utilities." A municipality's rights with respect to nonpayment of public utility service charges are included, in part, in sections 42 and 553 of the *MGA*. Section 42 sets out liability for public utility service charges, and section 553, which is located in Part 13 ("Liability of Municipalities, Enforcement of Municipal Law and Other Legal Matters"), Division 4 ("Enforcement of Municipal Law"), provides an enforcement mechanism for municipalities to recover unpaid utility service charges in certain situations.

Water, Drainage, and Sewer

Pursuant to sections 42(2)(a) and (b) of the *MGA*, the AUC considered whether the water, drainage, and sewer service charges at issue conformed to the rate structure established by Coaldale and/or were improperly imposed.

The AUC found that Coaldale properly applied its bylaws when it charged the property a flat monthly fee and a monthly consumption charge for one water meter, one water, and sewer connection, and one drainage service. However, the AUC found that the three-additional flat monthly charges to the property for individual dwelling units that did not have individual water meters or individual water and sewer connections, did not conform to the public utility rate structure established by Coaldale.

The AUC, therefore, concluded those charges were improperly imposed. The AUC ordered Coaldale to refund the complainants the flat monthly fees for water, drainage, and sewer charges billed for the additional three individual dwelling units that did not have an individual water meter, or an individual water and sewer connection.

Waste Management

The AUC accepted Coaldale's statement, previously communicated to the complainants, that their request to change the number of garbage bins assigned to the property must be made in writing, pursuant to section 4.1 of Bylaw 353-R-01-97. The AUC found that the complainants did not make this request. Therefore, the AUC found that the property was assigned four garbage bins and was being charged for four garbage bins. The AUC found that this was in conformance with Coaldale's public utility rate structure.

The AUC accepted that Coaldale's waste management service rates were based solely on the number of garbage bins and all residential customers were charged the same rate. The AUC also accepted that if Coaldale received a written request to reduce the number of garbage bins assigned to the property, Coaldale would assess whether the property would be sufficiently serviced by two bins for four residential units. Coaldale would exercise its discretion to either grant or deny the request based on whether two garbage bins would meet the needs of the property.

The AUC found that the waste management service rates were based on usage and Coaldale's rate structure was reasonable. The AUC found the rate structure was not discriminatory as all customers in the residential class paid the same amount per garbage bin.

Summary

The AUC ordered the Town of Coaldale to repay Ms. Eleanor Britz, the utility account holder, any amounts paid from November 12, 2015, to the date of issuance of this decision, for three flat monthly charges for each water, drainage and sewer service. The AUC indicated that in cases where these charges were unpaid, Coaldale could not pursue recovery of these charges.

BHEC-RES Alberta G.P. Inc. Forty Mile Wind Power Project (Decision 22966-D01-2018)
Wind Turbines - Consultation - Environmental Impacts - Noise Control

In this decision, the AUC considered whether to approve an application from BHEC-RES Alberta G.P. Inc. ("RES") to construct and operate a wind power project located in the County of Forty Mile No. 8 in southeastern Alberta.

The AUC approved the RES project, finding it was in the public interest having regard to its social, economic, and other effects, including its effect on the environment.

The Project

The RES proposed project consists of 115 wind turbines with a nameplate capacity of 3.465 megawatts ("MW") each, for an overall generation capacity of 398.475 MW. The project also consists of a new substation, designated as the Forty Mile 615S Substation, for connection of the project to the Alberta Interconnected Electric System.

Other Applied-for Power Plants in Area

Contemporaneous with RES' application, the AUC received applications for two other wind energy projects in the County of Forty Mile No. 8, from Forty Mile Granlea Wind GP Inc. (which is registered as Suncor Energy Inc. and referred to as Suncor) and Capital Power Generation Services Inc. ("Capital Power"). Suncor and Capital Power's proposed project areas were in close proximity to the RES project.

As discussed below, the AUC had to determine how best to consider the cumulative noise impacts and potential cumulative environmental impacts from the three projects.

Legislative Scheme

RES applied to construct and operate the project pursuant to sections 11 and 14 of the *Hydro and Electric Energy Act* ("*HEEA*").

Section 11 of the *HEEA* requires AUC approval prior to constructing or operating a power plant, and section 14 of the *HEEA* requires AUC approval prior to constructing or operating a substation.

The AUC explained that when considering an application for a power plant and associated infrastructure, it is also guided by sections 2 and 3 of the *HEEA*, and section 17 of the *Alberta Utilities Commission Act* ("*AUCA*"). Section 2 lists the purposes of the *HEEA*, including the following:

> (a) to provide for the economic, orderly and efficient development and operation, in the public interest, of the generation of electric energy in Alberta;
>
> (b) to secure the observance of safe and efficient practices in the public interest, in the generation of electric energy in Alberta; and
>
> (c) to assist the government in controlling pollution and ensuring environment conservation in the generation of electric energy in Alberta.

Section 3 of the *HEEA* requires the AUC to consider the purposes of the *Electric Utilities Act* ("*EUA*") when assessing whether a proposed power plant and associated infrastructure is in the public interest under section 17 of the *AUCA*. The purposes of the *EUA* include the development of an efficient electric industry structure and the development of an electric generation sector guided by competitive market forces.

Section 3 of the *HEEA* directs that the AUC will not consider whether the proposed power plant "… is an economic source of electric energy in Alberta or to whether there is a need for the electric energy to be produced by such a facility in meeting the requirements for electric energy in Alberta or outside of Alberta." Accordingly, the AUC did not take into account the potential need and cost of the project.

Section 17(1) of the *AUCA* states:

> Where the Commission conducts a hearing or other proceeding on an application to construct or operate a hydro development, power plant or transmission line under the *HEEA* or a gas utility pipeline under the *Gas Utilities Act*, it shall, in addition to any other matters it may or must consider in conducting the hearing or other proceeding, give consideration to whether construction or operation of the proposed hydro development, power plant, transmission line or gas utility pipeline is in the public interest, having regard to the social and economic effects of the development, plant, line or pipeline and the effects of the development, plant, line or pipeline on the environment.

The AUC considered its earlier decisions and explained that it assessed and balanced the negative and beneficial impacts of the specific project to determine public interest.

<u>Consultation</u>

Rule 007 stipulates that an applicant must conduct a participant involvement program before a facility application is filed with the AUC. The AUC noted that an effective consultation program might not resolve all landowner concerns.

The AUC found that RES designed its participant involvement program to ensure all potentially directly and adversely affected persons and all relevant and interested stakeholders understood the project, had an opportunity to voice concerns and to have those concerns addressed where feasible. The AUC considered the design and execution of RES' participant involvement program was consistent with the purpose of consultation and Rule 007 requirements.

The AUC found that Ms. Jenkins (an affected party) was aware of the project and had an adequate opportunity to have her concerns addressed through the consultation process.

<u>Environmental Impacts</u>

Project-Specific Environmental Effects and Mitigation

RES retained Golder Associates Ltd+. ("Golder") to prepare an environmental evaluation report for the project (the "EE Report"). The EE Report described the potential effects of the project on wildlife, which included direct habitat loss and alteration, habitat avoidance due to sensory disturbance, and increased wildlife mortalities. The EE Report included mitigation measures to minimize the project's effects to wildlife, including developing a Post-Construction Monitoring and Mitigation Plan (the "PCMM Plan") The PCMM Plan described how the post-construction monitoring and mitigation that RES proposed to implement during construction and operation to understand the project's direct effects on birds and bats, assess the effectiveness of mitigation, and determine whether additional or modified mitigation was necessary.

Vegetation, Wetlands, and Surface Water

The AUC found that the project's potential adverse effects on native vegetation and wetlands were significantly mitigated by the siting of the project infrastructure away from native grasslands, nature pasture and, with only very limited exception, directly in the wetlands.

The AUC found that the adverse effects on wetlands were acceptable from Alberta Environment and Parks' Wildlife Management's ("AEP WM") perspective. AEP WM was aware of the justifications for the relaxations of the wetland setbacks from roads when issuing the Renewable Energy Referral Report. The AUC found that RES' approach to siting roads and collector lines was reasonable in the circumstances.

As a condition of approval, the AUC directed that RES abide by all of AEP WM's requirements, recommendations, and directions outlined in AEP WM's Renewable Energy Referral Report and any additional commitments made in RES' responses to information requests from AEP WM.

Amphibians

The AUC noted RES' commitment to curtailing vehicle traffic along project access roads following major spring, summer, and fall rainfall events to reduce potential mortalities of northern leopard frogs and western tiger salamanders. The AUC found that this would reduce potential mortalities of northern leopard frogs and western tiger salamanders, which tend to emerge during and following major rainfalls.

The AUC required RES to complete amphibian surveys following AEP WM survey methodology prior to construction in situations where ground disturbance may occur within 100 metres of potential amphibian breeding pond habitat, including the northern leopard frog and western tiger salamander.

Birds and Bats

The AUC found that RES implementing operational mitigation was sufficient to bring the project's estimated corrected mortality rate below an average of four bats per turbine per year. The AUC considered this sufficient to address project-only impacts on bats. However, the AUC found that it may not be sufficient to address cumulative mortality impacts on migratory bats associated with the operation of existing and potential future wind power projects in the area.

With respect to the project's potential mortality impacts on bats and the long-term risk to migratory bat populations posed by wind power, the AUC considered that it would be useful and preferable to apply a "precautionary approach" where possible. The AUC found that this principle could be applied in this instance by requiring RES to implement a robust bat mitigation strategy and monitoring effort during operation.

Decommissioning and Reclamation

The AUC found that in its EE Report, RES confirmed that landowners would be consulted on decommissioning activities and that it will abide by the reclamation requirements of the *Conservation and Reclamation Regulation* under the *Environmental Protection and Enhancement Act*, which requires RES to obtain a reclamation certificate from Alberta Environment and Parks at decommissioning.

The AUC found that RES provided adequate assurance regarding the costs of decommissioning and reclaiming the project and that it would be sufficiently funded. This was based on RES' estimate of the costs of decommissioning and indication that the proceeds from salvaging project infrastructure would cover a significant portion of the expected costs of decommissioning and reclamation.

<u>Cumulative Impacts</u>

The AUC considered that the nature and extent of the potential cumulative impacts on birds and bats identified by AEP WM would only be known if and when other projects were constructed in the area. Because of the uncertain nature of the potential cumulative impacts that might arise, the AUC considered that a working group, comprised of the project proponents in the area and AEP WM, could be an effective means to consider and address potential cumulative effects that may arise.

The AUC required RES to form a working group with Capital Power and AEP WM to share wildlife information amongst the proponents and with AEP, and to implement mitigation measures as necessary to address any such cumulative effects. The AUC considered that it would be useful for all the proponents of other projects proposed in the area to participate in such a working group, including Suncor.

Accordingly, the AUC imposed the following condition of approval:

- RES will abide by any requirements, recommendations, and directions provided by AEP WM, whether in the context of a working group or otherwise, including any additional monitoring and mitigation that AEP WM considers necessary to address cumulative effects occurring from two or more projects within the local area, as defined by AEP WM.

<u>Noise Impacts</u>

The AUC accepted that:

(a) the cumulative noise levels from the project operating in its planned operating scheme with third-party energy-related facilities complied with applicable Rule 012 requirements; and

(b) the project was predicted to meet the daytime and nighttime permissible sound levels at all receptor locations in the project study area.

With respect to the Noise Impact Assessment ("NIA") prepared for RES' project, the AUC found that:

(a) the equipment used to conduct the field noise measurements of the third-party energy-related facilities met the requirements of Rule 012; and

(b) the acoustical model (the 2017 version of the CadnaA software package) and input data used to predict the cumulative sound levels complied with the AUC's ruling on modelling parameters for the three projects and met the requirements of Rule 012.

The AUC required RES to conduct post-construction comprehensive noise studies and an evaluation of low-frequency noise at specific receptors under representative operating conditions and in accordance with Rule 012.

Projects Must Implement Noise Mitigation Measures in Accordance With the Order in Which They Were Deemed Completed

With respect to cumulative noise effects, in Decision 23049-D01-2018, the AUC stated:

> Once an application is deemed complete, the Commission will issue a notice. In these circumstances, the notice will specify the date when the application was deemed complete. Any applications deemed complete after that point must take into account the preceding projects (those for which notice of application has been issued) for the purpose of calculating the cumulative sound level in Rule 012, and incorporate "proposed facilities" into NIAs and any applicable noise mitigation plans.

The AUC confirmed that the projects must implement noise mitigation measures in accordance with the order in which they were deemed complete. The RES project was deemed complete on February 3, 2018, prior to the Capital Power project, which was deemed complete on March 6, 2018. The AUC explained that this means that should RES' project come into operation and result in cumulative noise levels exceeding Rule 012 permissible sound levels, it is incumbent upon Capital Power to implement mitigation measures to address those effects.

<u>Visual Impacts and Shadow Flicker</u>

The AUC found the visual impacts resulting from shadow flicker produced by the project were likely to be low.

Alberta currently has no legislation, standards or guidelines in place regarding shadow flicker. However, RES and Ms. Jenkins referenced a German guideline which recommended that exposure to shadow flicker be limited to a maximum of 30 hours per year and a maximum of 30 minutes per day. RES indicated that the project complied with this guideline even though it was not required to do so.

RES stated it would consider mitigation measures such as micro-adjustments to turbine placements, tree planting, and window coverings to minimize the impact of shadow flicker. RES specifically committed to making micro-siting adjustments to turbines T111 and T112 to further reduce the potential for shadow flicker at Ms. Jenkins' residence.

The AUC acknowledged visual impacts resulting from the lights associated with the project; however, the decision of which turbines are lighted and to what extent, rests with Transport Canada.

The AUC noted that to minimize the visual impacts caused by lighting to the greatest extent possible, RES committed to using the minimum number of lights required by Transport Canada on the turbines, as well as the minimum number of synchronized flashes per minute and flash duration.

<u>Summary</u>

The AUC approved RES' wind power plant application pursuant to sections 11 and 14 of the *HEEA*, subject to conditions.

ATCO Gas, a division of ATCO Gas and Pipelines Ltd. Amendments to Customer Terms and Conditions for Gas Distribution Service (Decision 23532-D01-2018)
Proposed Amendments - Terms and Conditions - Customer Contributions

In this decision, the AUC considered the application by ATCO Gas, a division of ATCO Gas and Pipelines Ltd. ("ATCO Gas") for approval of amendments to its customer terms and conditions ("T&Cs") for gas distribution service.

For the reasons summarized below, the AUC found that ATCO Gas' proposed amendments:

(a) raised general rate design issues, the implications of which could not be fully considered outside of a rate design application; and/or

(b) constituted proposals not adequately supported by the evidence.

Consequently, the AUC denied ATCO Gas' request to amend its T&Cs.

<u>Proposed Amendments to Custom Service Letter Agreement</u>

ATCO Gas proposed changes to section 7(e) of the T&Cs; Schedule D – Custom Service Letter Agreement ("CSLA").

The AUC denied the proposed amendments, finding that such amendments might materially impact the allocation of capital costs on new facilities serving larger customers and the utility's investment policy, or otherwise impact rate design with consequent impacts to rate base and customer rates.

The Commission considers that such issues should not be considered in isolation as proposed amendments to the T&Cs. The proposed amendments would best be considered in a forum where the implications to the utility's cost of service and rate design can be fully considered and tested. The reasons for this finding are as follows.

Proposed Discretion to Waive CSLA Requirement

The AUC denied ATCO Gas' proposed amendments to section 7(e) of the T&Cs, which would have given ATCO Gas the sole discretion to waive the existing requirement that all new customers using greater than 500,000 gigajoules ("GJ") of gas per year have to sign a CSLA.

ATCO Gas submitted that it would exercise this discretion on a case-by-case basis, considering the expected investment, the expected length of time required for the expected revenue to offset the cost of the connection and any risk factors associated with the customer. ATCO Gas did not specify a minimum investment amount when deciding whether to require a CSLA.

In denying the requested discretion to waive the CSLA requirement, the AUC found that:

(a) the exercise of such discretion could result in different investment levels for similarly situated customers in the same class; and

(b) therefore, lead to unfair and inconsistent treatment of customers within the same rate class.

The AUC further found that the waiver of the CSLA requirement might impact ATCO Gas' investment level, thereby affecting rate base and potentially the rates paid by other customers.

The AUC found that investment level issues were not properly considered a "narrow in scope" amendment to T&Cs; but rather, were rate design issues.

Sections of the CSLA

For the reasons summarized below, the AUC denied ATCO Gas' proposed amendments to section 3.0 and 7.0 and the addition of a new section 5.0 to the CSLA.

With respect to section 3.0, the AUC denied ATCO Gas' proposed removal of language referencing the Performance Base Regulation ("PBR"). The AUC found that:

(a) the requested amendment to the formula in section 3.0 of the CSLA would constitute a change in investment policy affecting rate base; and

(b) therefore, was a change potentially affecting other distribution customers.

The AUC also denied ATCO Gas' proposed amendment to section 3.0 of the CSLA, setting out payments that the customer would be required to make to ATCO Gas immediately upon early termination of the CSLA.

The AUC found that ATCO Gas failed to demonstrate that the proposed termination payments were commensurate with ATCO Gas' investment or why such an investment would be recovered from other ratepayers in the event of such termination.

ATCO Gas proposed:

(a) the addition of a new section 5.0 to the CSLA to capture additional customer "comments and considerations"; and

(b) changes to section 7.0 of the CSLA to define "Customer Contribution" as the difference between the estimated costs of the *Specific Facilities* in section 4.0, *Additional Customer Considerations* as specified in section 5.0 … and any amount of ATCO Gas Investment as specified in section 3.0.

The AUC considered that the proposed amendment to section 7.0 related to, or had implications for, overall investment policy practices. Further, the AUC found the lack of clarity around the proposed section 5.0 (*Additional Customer Considerations*) created the potential for inconsistent treatment between customers and made the calculation of the potential Customer Contribution less transparent to ATCO Gas' stakeholders.

Custom Service Contract Demand Section of the High Use Delivery Service Rate Schedule

ATCO Gas proposed an amendment to the Custom Service Contract Demand Section of the High Use Delivery Service Rate Schedule to enable it to recover additional costs if the customer exceeds the contract demand.

The AUC denied the proposed amendments, finding that the proposed changes to the Custom Service Contract Demand Section of the High Use Delivery Service Rate Schedule had the potential to affect investment policy practices and cost allocation (Phase II rate design). The AUC explained that, because the proposed changes purported to impose a new charge on customers, such a charge might give rise to issues associated with cost causation. Further, the AUC found the proposed amendment was dependent on the execution of a CSLA, and therefore subject to the same investment policy practice related concerns raised in relation to the proposed amendment to section 7(e) of the T&Cs.

Summary

The AUC found that:

(a) the proposed amendments had potentially material implications for the allocation of capital costs on new facilities and the utility's investment policy;

(b) these proposed amendments otherwise impact rate design with consequent impacts to rate base and customer rates; and

(c) such issues should not be considered in isolation as proposed amendments to the T&Cs.

The AUC found that the proposed amendments would best be considered in a forum where the implications to the utility's cost of service and rate design can be fully considered and tested.

Decision

The AUC denied ATCO Gas' application, without prejudice to ATCO Gas reapplying for the proposed amendments in the context of an application that would fully address the matters raised in this decision.

ENMAX Energy Corporation Regulated Rate Tariff Terms and Conditions Amendment (Decisions 23637-D01-2018)
Facsimile - Terms and Conditions - Proposed Amendments

In this decision, the AUC considered ENMAX Energy Corporation's ("ENMAX") application for approval to amend sections of its regulated rate tariff terms and conditions ("T&Cs"). All proposed T&C amendments related to methods of customer communication.

The AUC approved the proposed amendments to sections 3.4, 8.5, 10.4(a), 10.4(d), 10.4(e), 10.4(g) and 10.4(h) of the T&Cs.

Proposed Amendments

The AUC approved removing all express references to "facsimile" from ENMAX's T&Cs found in the following sections:

(a) 3.4;

(b) 8.5;

(c) 10.4(a);

(d) 10.4(d); and

(e) 10.4(h).

The AUC approved this on the basis that facsimile is used only in limited circumstances.

The AUC approved the proposed amendments to sections 10.4(e) and 10.4(g). The AUC found these amendments to be reasonable, noting that the proposed amendments:

(a) added greater flexibility for electronic communication and certainty about the effective date of such communication; and

(b) provided greater convenience to customers because of the various forms of notice that can be provided to ENMAX.

The AUC also approved ENMAX's proposal to remove all express references to facsimile from its T&Cs, on the basis that facsimile was no longer relevant for most customers nor relied on by ENMAX for providing notice.

Summary

The AUC found ENMAX's proposed amendments to its T&Cs to be reasonable and approved them as filed.

Electric Facility Applications with Major Deficiencies Will No Longer Be Processed (Bulletin 2018-12)
Application Deficiencies

The AUC announced that it had amended its application process to better focus its staff and resources on those applications without deficiencies, effective immediately.

The AUC explained that processing applications with major deficiencies usually results in the repetition of reviews and administrative tasks due to the amount of time applicants typically required to address the deficiencies. The completion of the deficient portion of the application frequently resulted in amendments to other portions of the application.

The AUC intends to improve its application process by:

- suspending administrative and technical reviews on active applications that contain major deficiencies, and deciding whether or not to close the application; and

- assessing all new applications for completeness and closing those with major deficiencies.

Applicants are permitted to reapply when the application satisfies the Rule 007 information requirements and is free from major deficiencies.

Consultation to Develop a Regulatory Framework For Specified Penalties Related To Customer Care And Billing (Bulletin 2018-13)

Consultation - Specified Penalties - Customer Care and Billing

In this bulletin, the AUC announced the initiation of consultation to assist in developing a regulatory framework to support the implementation of specified penalties for non-compliance with the AUC's customer care and billing rules. The AUC expects to implement the specified penalty framework on January 1, 2019.

On June 11, 2018, *Bill 13: An Act to Secure Alberta's Electricity Future* came into force which gave the AUC the power to issue a notice of specified penalty to entities in violation of a Commission order, rule or decision. The AUC stated that it was reviewing and setting penalties for its rules related to customer care and billing. The entities affected by these rules include competitive retailers, municipally owned electric utilities, rural electrification associations, and entities regulated by the Commission.

The development of the regulatory framework to implement specified penalties for customer care and billing rules will proceed through two phases. In Phase 1, the AUC will review and consult with stakeholders on the current AUC rules that relate to customer care and billing. In Phase 2, the AUC will make rules and set specified penalties pertaining to customer care and billing.

The objective of the first consultation meeting is to review and, where necessary, revise the settlement system code rules (AUC rules 021 and 028) to set the requirements and obligations regarding the roles and responsibilities of the entities involved in the customer enrolment and de-enrolment process. The AUC indicated these areas were a source of many complaints.

NATIONAL ENERGY BOARD

Pacific Traverse Energy Ltd. Application for a 25-Year Licence to Export Propane Pursuant to Section 117 of the National Energy Board Act (A93367-1)
Licence to Export Propane - Natural Gas Liquid

In this decision, the NEB considered Pacific Traverse Energy Ltd.'s ("PTE") application for a licence to export propane for a 25-year term.

For the reasons summarized below, the NEB approved the application and issued a propane export licence to PTE, subject to the approval of the Governor in Council ("GiC").

<u>Legislative Scheme</u>

Section 116 the *National Energy Board Act* ("*NEBA*") prohibits the export or import of any oil or gas except in accordance with a licence issued by the NEB under section 117 of the *NEBA*.

Section 118 of *NEBA* provides that: "[o]n an application for a licence to export oil or gas, the [NEB] shall satisfy itself that the quantity of oil or gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada."

<u>Surplus Determination</u>

The NEB issued the applied-for propane export permit to PTE (subject to GiC approval), based on its determination that the quantity of propane being exported would not exceed the surplus remaining after due allowance for the reasonably foreseeable requirements for use in Canada.

With respect to the North American propane market, the NEB considered that:

(a) the market was not supply constrained, nor would it be during the proposed term of the export licence; and

(b) the market was generally liquid, open, efficient, integrated and responsive to changes in long-term supply and demand.

The NEB accepted PTE's analysis of current and forecasted Canadian propane demand. The NEB concluded that Canadian propane requirements would be met during the term of the approval, given what was expected to be a large propane resource, and given the integrated nature of the North American propane market.

The NEB acknowledged that propane markets could experience short-term disruptions as a result in changes in natural gas markets and seasonal variations in demand.

The NEB found that, over the longer term, if demand for propane saw a structural increase and an associated price response, then both the upstream and downstream industries would respond by increasing throughput to meet the increased demand. The NEB found that additional baseload demand, such as a waterborne export facility, that added throughput, and storage capacity, could improve the reliability and peak deliverability of the entire system.

<u>Summary</u>

The NEB approved PTE's application and issued a licence to export propane.

NEB Letter Decision Regarding Westcoast Energy Inc., Doing Business as Spectra Energy Transmission Application for Approval of 2018 and 2019 Transmission Toll Settlement (A93366-1)
Transmission Tolls - Settlement Guidelines

In this decision, the NEB considered an application by Westcoast Energy Inc., doing business as Spectra Energy Transmission ("Westcoast") for approval of it's 2018 and 2019 Transmission Toll Settlement (the "Settlement").

For the reasons summarized below, the NEB approved the Settlement as a package, finding that it resulted in just and reasonable tolls.

<u>The Settlement</u>

Westcoast explained that, under the Settlement, the forecast average rate base and revenue requirement for 2019 to set Westcoast's tolls in Zones 3 and 4 for 2019 would be updated to reflect the following:

(a) actual pipeline integrity capital expenditures;

(b) actual High Pine Expansion Project capital expenditures;

(c) actual Jackfish Lake Expansion Project capital expenditures;

(d) actual Wyndwood Pipeline Expansion capital expenditures;

(e) actual Spruce Ridge Program capital expenditures;

(f) any other expansion facility capital expenditures;

(g) actual capital expenditures for the Reliability and Maintainability Program, actual pipeline class location upgrade capital expenditures, any other compressor upgrade/replacement capital expenditures; and

(h) certain other capital expenditures agreed to in the Settlement.

Under the Settlement, tolls were calculated based on Westcoast's existing NEB approved toll design for Zones 3 and 4. However, the Settlement provided that Westcoast or any stakeholder may make any toll design proposals for consideration by the Toll and Tariff Task Force or make toll design applications to the NEB for changes during the term of the Settlement.

Fairness of Settlement Process

The NEB found that the Settlement was negotiated at arm's length. All parties to the Settlement actively participated in the negotiations, and those parties represented a wide base of Westcoast's shippers, gas producers and end-use markets.

The NEB found that the benefits of the Settlement outweighed the costs. The NEB also found that the Settlement satisfied the criteria for negotiated settlements set out in the NEB Settlement Guidelines.

BP Canada contested the Settlement indicating Westcoast did not explain whether the Settlement was put to vote and that Westcoast did not disclose the Depreciation Study to BP Canada. The NEB found that Westcoast adequately described the process by which the Settlement was obtained and named the parties that were signatories to the Settlement. The NEB accepted that Westcoast did not obtain an agreement with all its shippers and proceeded on the basis that it was a Contested Settlement in accordance with the NEB Settlement Guidelines.

Cost Increase and Rate Shock

The NEB found that the Settlement reasonably represented Westcoast's expected cost of providing service in 2018 and 2019. The NEB found that tolls were increasing over the Settlement period when compared to 2017 tolls, which was largely due to significant capital expenditures over the forecast period.

Depreciation Rates

Concurrent with the filing of the Settlement application Westcoast filed an updated depreciation study, prepared by Concentric Advisors (the "Depreciation Study").

The Settlement provided for an overall composite depreciation rate of 3.02 percent in 2018 and 2019, which was negotiated in consideration of the Depreciation Study. The Depreciation Study recommended a composite depreciation rate of 3.26 percent.

The NEB found that Westcoast's Depreciation Study supported a depreciation rate higher than that negotiated by the parties. The NEB found that further decreasing the depreciation rate beyond that negotiated would push costs into the future to be borne by long-term shippers thereby decreasing the benefits to the consenting parties.

Summary

The NEB approved the Settlement as a package. The NEB found that, as a package, the Settlement resulted in just and reasonable tolls.