REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA ENERGY REGULATOR

***Directive 065 and Manual 012 Updated to Align with Government Policy*, AER Bulletin 2020-03**
AER Bulletin

On March 11, 2020, the AER released new editions of *Directive 065: Resources Applications for Oil and Gas Reservoirs* and *Manual 012: Energy Development Applications Procedures and Schedules*. The AER updated s. 4.1.3 *of Directive 065* and s. 7.3.6 of *Manual 012* to align with Alberta Energy's Information Letter 2019-37 https://inform.energy.gov.ab.ca/Documents/Published/IL-2019-37.pdf) and AER Bulletin 2019-30, clarifying consent requirements when Crown mineral and disposal rights overlap.

For questions about AER requirements for disposal scheme applications, contact AER Customer Contact Centre at inquiries@aer.ca.

Directive 065 and *Manual 012* are available on the AER website, www.aer.ca.

***Oil Sands Environmental Monitoring Program Regulation and Regional Monitoring Approval Conditions*, AER Bulletin 2020-05**
AER Bulletin

The AER requires oil sands operators to conduct and support regional monitoring activities and to participate in regional monitoring programs. When the AER issues approvals under the *Environmental Protection and Enhancement Act* ("*EPEA*") to oil sands operators, conditions are added that require them to participate in regional monitoring programs, such as those run by the Wood Buffalo Environmental Association.

The Oil Sands Monitoring ("OSM") Program was established by the *Oil Sands Environmental Monitoring Program Regulation* (2013). This joint provincial-federal program performs various types of environmental monitoring across the oil sands regions of northern Alberta. Oil sands operators holding AER-issued *EPEA* approvals are required to participate in this program and pay a yearly fee. Under section 6 of the regulation, if an approval condition requires regional monitoring that is being done by the OSM program and the approval holder is meeting its obligations under the program, then the approval holder is deemed to be in compliance with that condition. The AER will check this "deemed compliance" annually.

Deemed compliance does not apply to certain conditions related to regional initiatives, such as participation in some environmental management frameworks under the *Alberta Land Stewardship Act*.

The AER will now issue letters annually to existing approval holders listing specific approval conditions that are considered satisfied under the regulation. All other conditions, including project area monitoring requirements, remain unchanged and are the responsibility of the approval holder.

***Process Change When Resuming Drilling Operations After Setting Surface Casing*, AER Bulletin 2020-02**
AER Bulletin

Previously, licensees who continued their drilling operations more than six months after it was started filed for and received a "resume approval." There was no operational reason for this approach. The secondary filing and issuance of another approval were necessary due to how AER legacy systems were configured. Recent changes to OneStop and the Digital Data Submission ("DDS") system have resolved this issue. Effective immediately, the AER is discontinuing this process. No additional application or approval is required when the licence has been acted upon by the well being spud, and the setting of surface casing has occurred, regardless of the length of time between this and the continuation of the drilling of the main hole. Licensees must provide the appropriate drilling activity notifications in the DDS system as explained in and required under *Directive 059: Well Drilling and Completion Data Filing Requirements*. Licensees should use the notifications "Drilling to Set Surface Casing Only" followed by "Drilling to Licensed Depth."

Licensees must still apply to resume drilling when performing additional drilling operations after a previous completion, suspension, or abandonment of their well, as outlined in section 3.010(1)(e) of the *Oil and Gas Conservation Rules* and section 7 of *Directive 056*.

***Request for Regulatory Appeal by Canadian Natural Resources Limited*, Regulatory Appeal No.: 1925150**
Request for Regulatory Appeal

In this decision the AER considered a request for a regulatory appeal filed by Canadian Natural Resources Limited ("CNRL"), under section 38 of the

Responsible Energy Development Act ("*REDA*"), of the Enhanced Oil Recovery Approval No. 12888 made by the AER on June 10, 2019, pursuant to the *Oil and Gas Conservation Act* ("*OGCA*") in favour of Marlboro Energy Ltd. ("Marlboro"). The AER dismissed the regulatory appeal request.

<u>The Law</u>

Section 38 of *REDA* states:

> 38(1) An eligible person may request a regulatory appeal of an appealable decision by filing a request for regulatory appeal with the Regulator in accordance with the rules.

Under section 36(a)(iv), an "appealable decision" includes:

> (iv) a decision of the Regulator that was made under an energy resource enactment, if that decision was made without a hearing.

Under section 36(b)(ii) of *REDA,* "eligible person" includes:

> (ii) a person who is directly and adversely affected by a decision referred to in clause (a)(iv).

The applicable deadline in the circumstances for filing a request for regulatory appeal is provided in section 30(3) the *Alberta Energy Regulator Rules of Practice* (the "*Rules*"):

> (m) in the case of a regulatory appeal in respect of any other appealable decision, no later than 30 calendar days after notice of the decision is issued.

CNRL filed its regulatory appeal request on October 2, 2019, which was outside of the 30-day deadline since the decision was issued on June 10, 2019.

<u>Reasons for Decision</u>

The request for regulatory appeal raised the following issues:

1. Whether to Allow CNRL to File the Late Regulatory Appeal Request

The AER determined that Marlboro did not provide CNRL with notice of or otherwise advise CNRL that it was going to or had filed an application with the AER. CNRL was, therefore, unaware of the application and was not able to file a statement of concern in accordance with the prescribed deadline. Consequently, the AER decided to accept CNRL's late filing of the request for a regulatory appeal.

2. If Not, Whether There Were Exceptional Circumstances Warranting a Reconsideration of the Decision in Question

Since the answer to the first issue was in the affirmative, there was no need to consider this issue.

3. Whether the AER Should Stay the Decision

Given Marlboro agreed to voluntarily stay the approval that is the subject matter of this regulatory appeal and all of the associated activities until the issuance of this decision, there was no need to address the stay issue.

4. If So, Whether to Grant the Regulatory Appeal and Refer the Matter to a Hearing

Since the answer to the first issue was in the affirmative, i.e. the late filing of the regulatory request was allowed, the AER considered the legal test for a regulatory appeal request.

The decision that was the subject matter of this appeal request was an approval issued pursuant to the *OGCA*, which is, in accordance with section 1(1)(j) of *REDA*, an energy resource enactment. Since the decision was made without a hearing, it was an appealable decision under section 36(a) of *REDA*.

CNRL asserted that, as a joint interest holder of eight percent of the associated PNG rights within the project Section 04-039-016W4M and a 21 percent interest holder in the adjoining Section to the south 32-039-16W4, it would be directly and potentially adversely impacted by the activities approved in the decision. CNRL also provided some technical concerns regarding the approved scheme and the potential for adverse impacts to its existing and future production, as well as Marlboro's complete disregard for AER requirements and its joint ownership agreements.

The AUC noted that the Court of Appeal in *Dene Tha' First Nation v. Alberta (Energy and Utilities Board)* provided guidance on what indicates a person may be directly and adversely affected. In particular, the AER must consider the "degree of location or connection" between the project or its effects and the person, and whether that connection is sufficient to demonstrate the person may be directly and adversely affected by the proposed activity. Reliable information is required that demonstrates a reasonable potential or probability that the person asserting the impact will be affected.

The AER noted that there is no dispute that CNRL is a joint interest holder of the PNG rights within relevant sections that are subject to the approval. The AER found that CNRL had not provided sufficient information to establish that it will or may be directly and adversely affected by the approval.

The AER found that CNRL was not directly and adversely affected by the decision. Consequently, CNRL was not an eligible person under section 36(b)(ii) of *REDA,* and the request for a regulatory appeal was dismissed.

ALBERTA UTILITIES COMMISSION

***Alberta Electric System Operator - Needs Identification Document Application and EPCOR Distribution and Transmission Inc. - Facility Applications - West Edmonton Transmission Upgrade Project*, Decision 23943-D01-2020**

Needs Identification Application, Transmission Lines

In this decision, the AUC approved a needs identification document ("NID") application from the Alberta Electric System Operator (AESO") and facility applications from EPCOR Distribution & Transmission Inc. ("EDTI") to construct and operate an 11-kilometre-long, 72-kilovolt transmission line and to alter the Poundmaker, Meadowlark and Garneau substations in west Edmonton (the "Project").

Process

The AUC received more than 100 statements of intent to participate from stakeholders objecting to EDTI's facility applications. Four groups of interveners formed, filed evidence and participated in the oral hearing. Some individuals also participated in the hearing, along with the Consumers' Coalition of Alberta ("CCA"), which objected to the AESO's NID application.

Legislative Framework

The AUC noted that these applications triggered the following legislative provisions:

- approval of the need for expansion or enhancement to the Alberta Interconnected Electric System ("AIES"), pursuant to Section 34 of the *Electric Utilities Act* ("*EUA*"), and

- a permit to construct and a licence to operate a transmission facility, pursuant to sections 14 and 15 of the *Hydro and Electric Energy Act.*

NID Application

The AESO prepared its NID application in response to a system access service request ("SASR") submitted by EDTI to reliably serve the growing demand for electricity in the west Edmonton area.

The AESO directed EDTI to apply with the AUC for the facilities to meet the need identified and to assist the AESO in conducting a participant involvement program for its NID application.

AESO Decision to File One NID Application for Two Developments

The AUC noted that the AESO's preferred transmission solution was comprised of two transmission developments:

- the replacement of three transformers with higher capacity transformers at Garneau Substation (the "Garneau Upgrades"), to respond to the load at risk in the event of a contingency to any of the three Garneau transformers; and

- the proposed 72-kV transmission line from Meadowlark to Poundmaker, and alterations to Meadowlark and Poundmaker substations, to respond to all the other contingencies.

While the AESO filed these two developments in one NID application, the AUC viewed them as distinct and separable. Based on the amount of load at risk and likelihood of unsupplied load, among other factors, it was also evident that the need for the Meadowlark to Poundmaker transmission line was more urgent than the Garneau Upgrades.

The AUC found that in this case, filing both developments under one NID was appropriate. However, the AUC outlined its concern regarding the potential for a less urgent project to become accelerated by being attached to a more urgent one. It noted that it would have greatly assisted the AUC if EDTI had considered these as separate projects and assessed the level of urgency of each development on a stand-alone basis.

Notwithstanding its concerns, the AUC found that while the Garneau Upgrades were less urgent than the Meadowlark to Poundmaker transmission line development, they were nonetheless required and that moving forward with both transmission developments was warranted.

Probabilistic Assessment and Cost-benefit Analysis

The CCA's expert filed cost-benefit analyses, which the AUC found informative. This evidence generally assisted the AUC's understanding of how the risks identified correlated with the costs of the Project and provided helpful context into the level of urgency of the need for the proposed solution's two developments.

However, the AUC agreed with the AESO and EDTI that calculating initial inputs was beyond the scope of a single NID proceeding. The AUC noted that it saw significant value in the AESO's initiative regarding probabilistic analysis and cost-benefit analysis in 2020.

Need for Transmission Development

The AUC was satisfied that the need for the Meadowlark to Poundmaker transmission line was clear and urgent. The evidence demonstrated that the project would resolve several different contingencies that, if left unaddressed, could result in a significant amount of load that EDTI would be unable to serve, potentially including critical loads such as hospitals, police stations, and the LRT.

While the AUC found there was a need at Garneau, the urgency of that need was less obvious. Unlike the levels of unsupplied load related to the Meadowlark to Poundmaker transmission line development, the amount of load at risk at Garneau did not appear to be as significant.

University of Alberta

In the AUC's view, it was important for EDTI and the AESO to assess the system under an N-G-1 scenario, where the University of Alberta's generation was assumed at zero. While the AUC acknowledged this scenario is unlikely, it was important for EDTI and the AESO to understand those consequences

The AUC noted that as the AESO moves forward with its initiative on probabilistic assessment, the manner in which distribution-connected generation is incorporated into planning studies would be an important factor to consider. The AUC recognized that distribution-connected generation is increasing in the province, and while that generation may not be as reliable as large-scale, traditional transmission-connected generation, it would be unwise to completely discount the contributions that these facilities can make to reliability in all cases.

The AUC found the general question of whether and to what extent N-G-1 is appropriate for SASR-driven distribution reliability-based NIDs was too broad a question for this proceeding. Notwithstanding that, it made note of the following statement by the CCA's expert:

> [I]t's almost bizarre that we have a large amount of generation right in the centre of this problem, and we are not having a relatively aggressive discussion with them, talking about every opportunity there is to firm up that generation in some way or to bring it to the table to avoid a very expensive project.

The AUC accepted the AESO's evidence that Transmission Must Run ("TMR") can only be used in areas with limited potential for load growth and that this was not the case in the Garneau area. Furthermore, the evidence indicated that the University of Alberta had no interest in providing emergency backup or in pursuing additional generation at this time.

The AESO's Distribution Deficiency Report Author's Guide, Distribution Load Shifting and EDTI Distribution Planning Criteria

The CCA argued that EDTI's Distribution Deficiency Report ("DDR") submitted to the AESO and filed as part of the NID application did not meet the requirement of the AESO's DDR Author's Guide because it did not include distribution-only options such as load shifting and distribution upgrades which might have resolved the need identified. In addition, the CCA said the report did not include a single-line diagram of EDTI's distribution system or information about existing or new distribution feeders such as the maximum or spare capacity and submitted that the NID application should be considered technically deficient on this basis.

The AUC found that the AESO's DDR Author's Guide is a guideline and that the AESO has the discretion to determine what information has to be included in a DDR. The AUC was also satisfied that the AESO obtained and filed the necessary information to consider whether distribution alternatives were feasible or superior options through information requests and the hearing process.

The AUC found, however, that had EDTI provided a single-line diagram of its distribution system and information on the spare capacity of its feeders, this would have clearly and succinctly answered questions on the ability of EDTI to address the problems via load shifting, which would have saved time and resources of many of the parties involved.

The AUC noted that while EDTI's practice of proactively shifting load allows it to get as close as possible to firm capacity at each area substation, it does not maximize overall area capacity. Under

EDTI's policy, a transformer contingency could occur at each and every area substation and no unsupplied load would occur. This achieves a level of reliability greater than N-1 as it does not properly account for capacity that could be provided by a nearby substation in the event of a contingency. Under the reliability criteria of other Distribution Facility Owners ("DFO(s)"), a point of delivery ("POD's") firm capacity would add capacity from adjacent substations. The amount of firm capacity would be limited by the amount of transformer capacity at nearby substations and by the amount of capacity on the feeders connecting the substations. The AUC found that EDTI's POD loading criteria does not align with that of other DFOs and has the potential to unnecessarily accelerate transmission development.

There was some indication that EDTI would transfer load between substations in the event of a contingency, but it was less clear to what extent the AESO or EDTI planners accounted for the ability of operators to do so in determining that additional capacity was needed.

The AUC was satisfied that while there was adjacent and unused transformer capacity at Rossdale that could provide support to Garneau, there was no available capacity on the feeders that connect Rossdale and Garneau and, therefore, no way to utilize Rossdale's available transformer capacity. To access that capacity, new distribution feeders would be required to be constructed. The AUC accepted EDTI's evidence on the costs and technical issues associated with those alternatives and found that they were not superior to the proposed transmission development. Although the AUC was satisfied in this case that the transformer replacements were in the public interest, it expected that EDTI would review its POD loading criteria to assess how it can be more aligned with other DFOs, and specifically to account for the capability that adjacent feeders and substations can provide in the operational time frame.

The AUC noted that the lack of available feeder capacity might have been the reason the AESO or EDTI did not discuss load shifting as an option in a contingency. If that was the case, it was not clearly stated, and this option was not eliminated in EDTI's DDR. The AUC noted that there is a level of overlap between the planning and operational horizons, and to completely separate them can only result in greater costs and inefficiencies.

The AUC advised against the practice of over-relying on transmission solutions and encouraged the AESO and DFOs to attempt to find innovative means to delay the need for transmission projects, where it is prudent and appropriate to do so. Importantly, in evaluating whether it is in the public interest to approve a transmission solution, the AUC requires a full analysis of what operational measures were considered and why such measures were eliminated in favour of new infrastructure as a solution.

Conclusion on NID Application

The AUC found that no interested person demonstrated that the AESO's assessment of the need for proposed transmission upgrades in west Edmonton was technically deficient or that approval of the NID would not be in the public interest.

Facility Applications

EDTI filed facility applications to:

- Construct an 11 km 72-kV transmission line between the Poundmaker and Meadowlark substations. EDTI's application included a preferred route and an alternate route for the proposed transmission line.
- Construct a new fibre optic line between the existing Poundmaker and Meadowlark substations, using the proposed transmission line structures for the majority of its route.
- Alter the existing Poundmaker Substation by adding one 240/72-kV, 100/133-MVA transformer, one 240-kV circuit breaker, and one 72-kV circuit breaker.
- Alter the existing Meadowlark Substation, located in the community of Lynnwood, by adding two 72-kV circuit breakers.
- Alter the existing Garneau Substation by replacing three 72/14.4-kV, 40-MVA transformers with three 72/14.4-kV, 60-MVA transformers.

Consultation

The AUC recognized that many stakeholders had concerns about the participant involvement program for the proposed transmission line. However, the AUC was of the view that the participant involvement programs were sufficient to communicate to potentially affected parties the nature, details and potential impacts of the Project and gave parties an opportunity to ask questions and to express their concerns.

Visual and Property Impacts

Although the AUC recognized that the Project would change the viewscape along the preferred route, it found that visual impacts could be sufficiently mitigated.

The AUC found that the preferred route would result in the least impact on property values in terms of the overall project because a significant portion of the preferred route followed a transportation and utility corridor ("TUC") as well as existing linear infrastructure such as Whitemud Drive. It found that property value impacts could be mitigated.

Electric and Magnetic Fields and Health / Safety

The AUC placed significant weight on the World Health Organization's conclusion that, based on available research data, exposure to electromagnetic fields ("EMF") is unlikely to constitute a serious health hazard. The AUC also placed weight on Health Canada's conclusion that exposure to EMF from transmission lines is not a demonstrated cause of any long-term adverse effect on human or animal health.

The AUC found that there would be no material difference between the expected magnetic fields produced by an overhead versus an underground line at the nearest homes, schools, daycares, and playgrounds. It also accepted that the expected electric and magnetic fields produced by the proposed line, whether underground or overhead, will be very low and well below recognized standards, as noted by the expert witnesses for both the applicants and the interveners.

Environment and Noise

The AUC found that the environmental effects predicted for the project were consistent with transmission line development in the TUC and an urban setting. With the diligent application of proposed mitigation and monitoring measures, the environmental effects from construction and operation of the proposed transmission line will be adequately mitigated.

The AUC found that the proposed and existing substation facilities will comply with the requirements of Rule 012. It was also satisfied that the proposed transmission line will not be a significant source of audible noise.

Routing of Transmission Line

The AUC accepted EDTI's evidence that the potential impacts associated with its proposed preferred and alternate routes were similar and reflected the highly developed urban area within which the Project was proposed. Each route used existing linear developments to minimize incremental impacts and was located primarily on public land. In particular, the AUC found that the preferred route's use of the TUC for slightly less than one-half of its length was the primary consideration in its favour and that it was superior in this regard to the alternate route, which makes almost no use of the TUC.

The AUC noted the TUC is publicly-owned land that was created to provide a corridor within which utility infrastructure, including pipelines and transmission lines, could be grouped with other linear features. The TUC was, therefore, an obvious and superior routing choice for the proposed transmission line.

The AUC noted that the preferred and alternate routes were similar in length, and their cost estimates were almost identical.

For these reasons, the AUC found the preferred route will result in lower impacts than the alternate route.

Decision

The AUC approved the AESO NID application, and the applications to alter and operate the Poundmaker, Meadowlark, and Garneau substations. The AUC also approved applications to construct a transmission line and a fibre optic line and will issue permits and licences for the transmission line following the written consent of the Minister of Infrastructure regarding facilities in the TUC.

***AltaGas Utilities Inc. 2018 Depreciation Study Compliance Filing Pursuant to Decision 24161-D03-2019,* AUC Decision 25368-D01-2020**
Rates - Depreciation Study - Compliance Filing

In this decision, the AUC considered whether to approve AltaGas Utilities Inc. ("AltaGas")'s compliance with the AUC's directions in Decision 24161-D03-2019, and AltaGas's request to amend Rider F for collection of the resulting deficiency. The AUC found that AltaGas complied with all of the AUC's directions and approved the amended 2020 Rider F.

Compliance with AUC Directions

AUC directions 1, 4, 5, 7, 8, 9 and 10 from Decision 24161-D03-2019 pertained to this compliance filing.

Direction 1

The AUC directed AltaGas to incorporate the depreciation rates reflective of the proposed changes to the depreciation parameters in its compliance filing to this decision.

AltaGas provided a summary of the approved depreciation parameters for all accounts and corresponding depreciation rates. AltaGas also provided financial schedules showing the calculations incorporating the changes to depreciation rates and the effects on depreciation expense and revenue requirement for 2018, 2019, and 2020. The AUC was satisfied that the calculations were accurate and found that AltaGas had complied with Direction 1.

Direction 4

The AUC directed AltaGas, for 2018, 2019 and future years, to charge site remediation costs to operating costs and not to cost of removal where there are no related asset retirements occurring concurrently or within a reasonably foreseeable period of time and the existing assets continue to be used. AltaGas was further directed to reflect this change for all accounts that include site remediation costs as part of net salvage, in its compliance filing.

AltaGas stated that the site remediation costs were all associated with Account 46700 (Measuring & Regulating Station Equipment), which, in 2018 and 2019, totalled $87,332. Of the $87,332, $15,006 was associated with assets that would continue to be in use and, therefore, that amount had been charged to operating costs in 2019. The remaining $72,326 were remediation costs associated with assets that were retired in 2019 or earlier. AltaGas also advised that these costs do not affect the 2017 notional rate base and depreciation expense and, therefore, had no impact on K-bar calculation mechanics.

AltaGas stated that effective January 1, 2020, it updated its procedures for all accounts to ensure only site remediation costs associated with assets that were either in the process of being retired or have been retired, would be included as part of cost of removal.

The AUC was satisfied with AltaGas' response and found that AltaGas complied with this direction.

Direction 5

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

AltaGas explained that its practice for the allocation of cost of removal is based on project type. For projects involving the removal of existing assets from service with no corresponding asset replacement, 100 percent of the actual costs incurred are recorded as cost of removal. For projects involving the removal of existing assets from service and a corresponding asset replacement, an allocation of actual costs incurred is recorded as cost of removal. For these project types, a cost estimate is prepared in support of the project, including all costs for both the removal and replacement components. As actual project costs are incurred, they are allocated to the removal and replacement components based on the proportionate share determined in the project cost estimate.

The AUC found that AltaGas complied with this direction. However, the AUC considered that additional information would be helpful in fully understanding the allocation of cost of removal for projects involving the removal of existing assets from service and a corresponding asset replacement. Accordingly, AltaGas was directed, as part of its next depreciation study, to provide such additional detail.

Directions 7, 8, 9 and 10

The AUC issued specific directions regarding applied-for changes to AltaGas's depreciation parameters. Specifically, the AUC directed AltaGas to incorporate particular negative net salvage rates for certain accounts. The AUC reviewed the calculations in AltaGas' financial schedules and resulting depreciation rates and was satisfied that the calculations were accurate and in accordance with the directions from Decision 24161-D03-2019.

Accordingly, the AUC found that AltaGas complied with these directions.

Carrying Costs

AltaGas requested carrying costs in the amount of $181,755. The AUC reviewed the carrying costs calculations in the financial schedules and was satisfied that the calculations were accurate and in accordance with *Rule 023: Rules Respecting Payment of Interest*. Accordingly, the AUC approved the carrying costs as applied for.

Revenue Shortfall

AltaGas advised that the updates to the depreciation parameters approved in Decision 24161-D03-2019 would result in a revenue requirement shortfall of $11.0 million for 2018, 2019 and 2020 collectively.

AltaGas proposed to recover the remaining revenue requirement shortfall and carrying charges of $4.8 million through an adjustment to its 2020 Rate Rider F from April 1 through December 31, 2020. AltaGas submitted that the proposed incremental increase to the 2020 Rate Rider F would result in bill impacts for each customer class below 10 percent. AltaGas also submitted that its proposed approach mitigates the possibility of rate shock in 2021 rates should the $4.8 million revenue requirement shortfall and carrying costs be deferred to 2021 rates instead.

The AUC reviewed the amended Rate Rider F and was satisfied that the calculations were accurate. The AUC also approved the methodology for recovery of the deficiency, using the same rate class allocation methodology as approved for its 2020 Rate Rider F in Decision 24883-D01-2019. Accordingly, the AUC approved the amended 2020 Rider F, as applied for.

***AltaGas Utilities Inc. Busby Pipeline System Project*, Decision 25306-D01-2020**

Facilities - Gas Pipeline - Project Need

In this decision, the AUC considered whether it was in the public interest to approve an application by AltaGas Utilities Inc. (“AltaGas”) for the Busby Pipeline System Project (the “Project”). The AUC found that approval of the need for the Project and the construction and operation of the Project was in the public interest.

Legal Framework

The AUC’s *Rule 020: Rules Respecting Gas Utility Pipelines* allows for an applicant to apply for approval of both the need and the facility licence in a single proceeding. Pursuant to these provisions, a gas utility can seek approval to construct and operate a new gas utility pipeline under the *Pipeline Act* and the *Gas Utilities Act* without prior approval of the associated forecast capital expenditures.

Project Need

AltaGas explained that its gas distribution system for the hamlet of Busby and the surrounding rural areas (the “Busby System”) is supplied by an AltaGas-owned, 27-kilometre-long, high-pressure aluminum pipeline (the “Pipeline”). The Pipeline is connected to AltaGas’ metering and regulating station MN027, which is upstream of a Tidewater Midstream and Infrastructure Ltd. (“Tidewater”) compressor station, near the town of Legal where gas supply is provided by Tidewater.

AltaGas stated that its Busby System is licensed for a maximum operating pressure of 450 pounds per square inch gauge (psig) and typically receives a pressure of 270 psig from Tidewater’s pipeline at the MN027 station. AltaGas stated that it is unable to operate its Pipeline at pressures optimal for gas distribution in the area because of the low pressure.

AltaGas added that the customer demand growth on the Busby System pipeline had been six percent annually, and it expects this growth to continue. It also noted that the Busby System is unable to support this growth in the area at the current supply pressure.

Project Alternatives

To maintain safe, reliable service to its customers and to allow for customer growth in this area, AltaGas evaluated five alternatives to increase the capacity of the Busby System.

AltaGas stated that the status quo was not a viable alternative as pressures in the Pipeline had dropped to a point where safe, reliable service was at risk. Three other alternatives included:

1. connect to the AltaGas Pickardville system to the north;

2. loop the existing high-pressure system; or

3. alternative route to connect to the discharge side of a Tidewater Compressor Station.

AltaGas noted that all of these alternatives were viable options. However, none of these alternatives were cost-effective, with cost estimates ranging from $0.8 million to $6.1 million.

AltaGas stated its proposed alternative is to construct a new 0.86-kilometre-long, 168.3-millimetre steel pipeline to connect to the discharge side of a Tidewater Compressor Station and provide higher pressure at station MN027. The proposed pipeline would allow for the Busby System's current and future needs, as well as accommodate future expansion to supply restricted areas in the AltaGas Barrhead, Westlock and Morinville districts. The cost estimate for this alternative was $0.4 million. This was the preferred alternative as it was the lowest cost option that is able to provide adequate system pressures.

Environmental Assessment

AltaGas retained Vertex Professional Services Ltd. to complete a pre-construction site assessment and environmental protection plan for the Project. The report included a review of the current environmental conditions and mitigation measures to reduce potential adverse effects of the Project on the environment.

AUC Findings

Based on the evidence provided by AltaGas, the AUC found that the Project was required to provide reliable, uninterrupted service to existing and future AltaGas customers. Accordingly, the AUC found that AltaGas demonstrated there was a need for the Project.

The AUC also found that the proposed alternative provided a cost-effective technical solution to ensure continued gas supply for AltaGas customers in the affected areas. It was also an effective means of meeting the long-term demand requirements. With respect to the other alternatives presented, the AUC accepted that the alternative recommended by AltaGas is the least cost option, is capable of being expeditiously implemented and is expected to alleviate the existing operational low-pressure concerns.

The AUC found that the potential environmental impacts of the project were sufficiently addressed in AltaGas' environmental protection plan filed in support of its application. The AUC accepted AltaGas' commitments to implement the recommendations presented in the environmental protection plan to reduce the risk of potential adverse environmental impacts of the Project.

Overall, the AUC found that it was in the public interest to approve the need for the Project and the construction and operation of the Project.

***Amendments to AUC Rule 003,* AUC Bulletin 2020-09**

AUC Rules

On March 23, 2020, the AUC approved amendments to Rule 003: *Service Standards for Energy Service Providers*, with an effective date of March 23, 2020. The changes reduce reporting requirements to increase efficiency and reduce regulatory burden.

In alignment with the AUC's strategic plan theme to increase efficiency and to limit regulatory burden, the AUC has approved additional changes to reduce reporting requirements under Rule 003. Specifically, reporting under Section 3.4.3 is no longer required. The AUC has updated the reporting templates to reflect this change.

Entities may still provide the AUC with a self-disclosure statement as outlined in sections 5(4) and 5(5) of Rule 032. These self-disclosure statements can be sent to the enforcement division at enforcement@auc.ab.ca.

***ATCO Electric Ltd. - Hanna Region Transmission Development Deferral Account Compliance Filing*, Decision 24753-D01-2020**

Rates

In this decision, the AUC set out its determinations on the application by ATCO Electric Ltd. ("ATCO") for approval of its Hanna Region Transmission Development ("HRTD") deferral account compliance filing. The AUC found that ATCO complied with six of the directions from Decision 22393-D02-20191 but that it had not complied with three other directions. ATCO was directed to file a second compliance filing by April 20, 2020, to address the AUC's findings.

Background

On February 3, 2017, ATCO filed an application with the AUC requesting approval of capital additions totalling $688.0 million for its HRTD program for the years 2012-2015. The AUC issued a confidential Decision 22393-D02-2019, a public summary of that decision, and a redacted version of the confidential decision in June of 2019.

In Decision 22393-D02-2019, the AUC set out nine directions to be addressed in a compliance application and directed ATCO to refile its HRTD program compliance application. The compliance application was assigned Proceeding 24753.

Compliance With Directions from Decision 22393-D02-2019

In its application, ATCO responded to the nine directions arising from Confidential Decision 22393-D02-2019. The AUC addressed conditions 2, 3, 4, 5, 6, 7 and 8 in detail in its decision.

Direction 2 - The AUC directed that chartered aircraft charges for travel between Edmonton and Calgary be removed in their entirety, and revised travel costs based on lower cost options be provided.

ATCO provided three different travel options, which included labour costs for those travelling. Having regard to the labour costs, travel by commercial airline was the lowest cost option, and ATCO removed $0.061 million from its filing.

The AUC agreed that it was necessary to consider both the direct costs associated with each travel option (i.e., ticket price) and the productivity or lost time associated with each travel option. It also accepted evidence that in-person meetings were necessary. The AUC found that ATCO complied with Direction 2 and approved the recovery of total travel costs of $56,856.

Direction 3 Legal Costs

Direction 3 - With regard to specified invoices and the legal costs for the work performed that was attributed to the HRTD program, including any invoice submitted by Bennett Jones [LLP] to ATCO Electric in a pre-LEAF [Legal Expenditure Authorization Form] and LEAF format, ATCO Electric is directed to identify, summarize and remove every expense of a similar nature to those noted in sections 7.3.1, 7.3.2, and 7.3.3 …. The Commission finds them to be unnecessary or beyond what could be considered a reasonable expenditure.

The AUC described the legal costs in decision 22393-D02-2019 as follows:

7.3.1 "there are allocations … that appear to be related to services or capital projects other than the HRTD Program" and "… costs that appear to be improperly charged to the HRTD Program"

7.3.2 … concerns with the nature of the costs being charged … as being charged to the HRTD Program".

7.3.3 "concerns with the nature of the costs being charged to the HRTD Program" and "The costs appear to be for work that should only have been performed by internal resources" and accordingly, these costs "appear to be improperly charged to the HRTD Program".

ATCO's response to Direction 3 was two-fold:

> (i) it argued that the AUC should have advised ATCO of its concerns with these types of expenses and its supporting documents before the AUC issued its decision to allow ATCO to provide further support; and
>
> (ii) it presented further arguments and materials with respect to each of the three areas of concern, subsections 7.3.1, 7.3.2, and 7.3.3, to support its continued view that the majority of the costs in these categories of expenses should be allowed, except for certain costs identified by ATCO in its compliance response.

ATCO identified a total of $42,935 in legal costs it considered pertain to Direction 3. These costs represented legal costs related to cost and performance audit services in the amount of $13,690 and legal costs related to other projects in the amount of $29,245.

Direction 4 Legal Costs

Direction 4 - In light of ATCO Electric's acknowledgement that the hourly rates at the partner level exceed peer rates by approximately 10 per cent, ATCO Electric is further directed to apply a reduction of 10 per cent to the legal fees recorded at the partner level as charged by Bennett Jones to the HRTD program.

After applying the $42,935 reduction to legal fees attributable to Direction 3, ATCO determined a reduction of $325,130 related to hourly rates charged at the partner level that the AUC found exceeded peer rates by approximately 10 per cent.

Direction 5 Legal Costs

Direction 5 - ATCO Electric is directed to apply a 10 per cent reduction to the remaining legal fees of Bennett Jones, in recognition of the long-standing relationship between the two parties and the volume of the work being conducted.

ATCO determined a reduction of $177,666 related to the overall 10 per cent reduction that was directed by the AUC to be applied to the remaining legal fees in recognition of the long-standing relationship between Bennett Jones and ATCO.

The Consumers' Coalition of Alberta ("CCA") argued that ATCO's calculation of the impact of Direction 5 should have taken into account the impact of Direction 4 on the amount of remaining legal fees that the further 10 per cent reduction was applicable to.

AUC Findings on Directions 3, 4 and 5 - Legal Costs

The AUC noted that directions 3, 4 and 5 were the subject of a review and variance application in Proceeding 24754. In its review application, ATCO generally raised the same issues that it raised in this compliance proceeding concerning individual time entries for the legal fees incurred, as well as the general percentage reductions to the legal fees.

The AUC released Decision 24754-D01-201929 on December 9, 2019, dismissing ATCO's request in Proceeding 24754, finding that ATCO had not satisfied the requirements for a review.

The AUC found that ATCO's compliance with Direction 3 was incomplete. The costs identified by ATCO as requiring removal in response to Direction 3 were identified based on ATCO's determination as to whether those costs were to be removed. Direction 3 required ATCO "to remove every expense of a similar nature to those noted in sections 7.3.1, 7.3.2 and 7.3.3 of Decision 22393-D02-2019". It was not invited to argue whether those costs should be removed. The AUC made a finding of fact in Decision 22393-D02-2019 that these costs were "unnecessary or beyond what could be considered a reasonable expenditure." ATCO was expected to comply with this direction or to seek a review of this direction, which it did. Its disagreement with the AUC's findings regarding these costs was examined in the review proceeding and dismissed.

With respect to Direction 5, the AUC disagreed with ATCO's calculation and confirmed that the impact of Direction 4 should be taken into account prior to the determination of the impact of the 10 percent reduction under Direction 5. This is because Direction 4 found that legal fees at the partner level were subject to a 10 per cent reduction as they were in excess of similar peer rates. Had ATCO submitted its legal fees at the partner level in accordance with peer rates from the outset of Proceeding 22393, the impact of doing so would be the same as having applied Direction 4 to legal fees prior to determining the effect of Direction 5.

The AUC found that to comply with Direction 5, ATCO must reduce partner level legal fees to the amount determined in Direction 4 and take that reduction into account when complying with Direction 5.

The AUC was satisfied with ATCO's calculation of the impact of Direction 4. However, the attendant calculation will be required to change as a result of ATCO's compliance with Direction 3. More specifically, further reductions for legal costs related to ATCO's compliance with Direction 3 will be required to inform the final calculation of the impact of Direction 4.

ATCO was directed to include the impact of complying with Direction 3 in applying Direction 4 and, further, to take this amount into consideration in its application of Direction 5 in a further compliance filing.

Direction 6 - Salvage Costs

Direction 6: The Commission will not approve salvage costs with respect to ATCO Electric's poles and conductor for project numbers 58473, 58571 and 58936 until sufficient detail is submitted…

In response to this direction, ATCO submitted detailed support in relation to the salvaging of its poles and conductor assets for the projects identified.

The AUC found that the supplementary salvage detail provided by ATCO was helpful in determining the prudence of the salvage costs related to the poles and conductor for the three projects identified. It found that ATCO complied with Direction 6, and its salvaging costs with respect to poles and conductors for project numbers 58473, 58571 and 58936 were approved.

Direction 7 - Miscellaneous Disallowed Costs

Direction 7 - The principles set out in Decision 21206-D01-2017 regarding the recovery of charges relating to non-taxable employee benefits, late payment penalties and finance charges apply equally to the costs incurred on the HRTD program. The Commission … directs ATCO Electric to remove the amounts quantified as part of its compliance filing to this decision.

In response to this direction, ATCO identified $53,113.62 in costs similar to those disallowed in Decision 21206-D01-2017 and calculated that a reduction in these capital costs results in a $28,000 revenue requirement refund to the AESO.

ATCO explained that it had inadvertently included land access payments in the calculation of late payment penalties in Proceeding 22393 and was seeking to correct the error. It explained that interest associated with land access payments is incurred due to the timing of payments in relation to land acquisition as compared to construction.

ATCO advised that in previous instances where land access has been negotiated through the Surface Rights Board (SRB), the SRB has directed ATCO to pay interest "on any part of the compensation that was payable on the date the right-of-way agreement was executed or the date the right-of-entry order was issued, also known as the effective date" under the *Surface Rights Act*. Consequently, ATCO asserted that interest on land access payments is not avoidable and is appropriately included in project capital costs.

The AUC found that ATCO removed the directed amounts and corrected an error found in its Proceeding 22393 rebuttal evidence. ATCO had incorrectly included interest payable on land access payments in late payment penalty or finance charges and requested that these be included in approved capital costs.

The AUC found that it was reasonable for ATCO to include the payment of interest in the negotiated settlements it entered into with landowners. It found that the applied-for deduction of $53,113.62 was compliant with Direction 7.

Direction 8 - Business Training Costs

Direction 8 - The Commission therefore disallows the expenditures related to "Business Training" and ATCO Electric is directed to remove from rate base the value of the related expenditures in its compliance filing.

In response to this direction, ATCO estimated that 12 percent of its training costs pertained to business training. Accordingly, ATCO removed $132,000 from requested capital additions. This adjustment resulted in a $62,000 revenue requirement refund to the AESO.

The AUC considered that the most accurate way to complete this task would require that all business training expenditures included in the HRTD projects subject to Decision 22393-D02-2019 be individually identified, quantified and removed from rate base. However, the AUC accepted ATCO's evidence that given that the size of any variance from its estimate would likely be relatively small compared to the level of work required, it was reasonable to apply an estimate.

AUC Announcement - Carolyn Dahl Rees Appointed to AUC

AUC Appointments

Veteran utility and regulatory lawyer Carolyn Dahl Rees is rejoining the AUC as a Commission member. Ms. Dahl Rees was the AUC's first interim chair at its launch in 2008, and served as a vice-chair with the AUC's former chair, the late Willie Grieve, until July 2012.

Ms. Dahl Rees was appointed for a five-year term as a Commission member on Wednesday, March 25, 2020, by the lieutenant-governor in council on a recommendation from Energy Minister Sonja Savage, following a third-party executive search process. Ms. Dahl Rees started on March 31.

***Capital Power Generation Services Inc. - Halkirk 2 Wind Power Project Time Extension*, Decision 25047-D01-2020**

Extension of time - Wind farm requirements

In this decision, the AUC granted Capital Power Generation Services Inc. ("Capital Power") a time extension to construct the 148-megawatt wind power plant and associated substation designated as the Halkirk 2 Wind Power Project (the "Project") and a revision to a stakeholder consultation date, which was Condition 6 of Approval 22563-D02-2018 (the "Original Approval").

Introduction

The Original Approval and associated permit allowed Capital Power to construct and operate the Project. Construction was to be completed by December 31, 2019. On November 1, 2019, Capital Power filed applications with the AUC for approval of a time extension to complete construction of the Project. Capital Power also applied for a revision to the date specified in Condition 6 of the Original Approval.

Discussion

Capital Power stated that due to commercial reasons including uncertainty surrounding the provincial regulatory regime in 2019, it had not yet commenced construction of the Project and would not meet the construction completion date of December 31, 2019. It requested a new completion date of December 1, 2022, for the Project.

The applications also requested approval to revise the date specified in Condition 6 of the Original Approval, which required consultation with a stakeholder regarding the location of a turbine and advising the AUC of the results of that consultation. Capital Power requested that the AUC extend the date specified for Condition 6 to July 15, 2021.

Findings

The AUC found that Capital Power demonstrated that the requested time extension was of a minor nature and was not expected to affect the compliance of the Project with the permissible sound levels outlined in Rule 012, nor result in any new effects on the environment. The AUC considered it significant that the requested time extension was for less than three years, which would result in an in-service date less than five years from the Original Approval.

The Original Approval addressed noise issues for a proposed new residence. The AUC again confirmed that to achieve compliance with Rule 012: *Noise Control*, permissible sound levels accounting for the new residence had to be achieved. Given the uncertainty with the number of storeys associated with the new residence, which would affect the operating modes of certain turbines to achieve permissible sound levels, the AUC did not alter these conditions of the Original Approval. The AUC directed Capital Power to operate the wind turbines in such a manner as to achieve compliance with the permissible sound levels accounting for the new residence.

The AUC expected Capital Power to update all wildlife surveys and the renewable energy referral report as needed to ensure they remain current.

The AUC noted that Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants* came into force on July 1, 2019, and applies to all wind projects approved after September 1, 2019. The AUC noted that Capital Power must comply with the requirements of Rule 033, including the requirement that approval holders submit to AEP and the AUC annual post-construction monitoring survey reports for the period recommended by AEP in the Project's referral report, and amended a condition of the Original Approval to reflect this. The AUC further noted that following Rule 033 coming into force, a number of the environmental conditions imposed in the Original Approval were no longer necessary.

The AUC also noted that the *Conservation and Reclamation Regulation* was amended to specifically address the reclamation of wind projects in Alberta. The effect of these amendments is that "renewable energy operations," which include wind projects, are now expressly subject to the reclamation obligations. Operators of renewable energy projects are now required to obtain a reclamation certificate at the project's end of life. This made another condition from the Original Approval unnecessary.

The AUC approved the change in timing for Condition 6 and found the requested time extension and the alteration of the timing of Condition 6 to be in the public interest.

COVID-19 Announcements and Bulletins

COVID-19 Updates

AUC Defers Live Proceedings to Reduce COVID-19 Risk (AUC Bulletin 2020-06)

On March 12, 2020, the AUC announced that, as part of its response to COVID-19, the AUC would immediately defer all public hearings, consultations or information sessions until further notice. The AUC indicated that, should there be an essential economic requirement to proceed with a hearing or other normally public proceeding, written or remote-participation options would be explored with parties.

AUC Announces Two Measures in Response to COVID-19 Threat (AUC Bulletin 2020-07)

On March 17, 2020, the AUC announced the following two measures in response to the COVID-19 risk:

- AUC offices are closed. However, AUC teams remain engaged on files; and
- the AUC would, in response to a request from retailers and distribution utilities, lead an industry-wide process for consultations to coordinate customer relief efforts.

AUC Supports Government Directed Option Utility Bill Payment Deferral (AUC Bulletin 2020-08)

On March 18, 2020, the AUC announced its support for the Alberta Government's direction, on the same day, that consumers be given the option to defer payment of their utility accounts in light of the financial pressures arising from the COVID-19 pandemic. The initial deferred payment period would last for 90 days with the potential for further extensions.

The AUC indicated it would lead and coordinate the overall approach to the payment deferral policy. The AUC would be bringing together utility and consumer representatives to provide recommendations to the AUC on the regulatory treatment of the deferred account balances and carrying costs arising from the deferred collection of accounts.

AUC Supports Implementation of 90-Day Utility Bill Payment Deferral Option (AUC 2020-03-18-Announcement)

On March 18, 2020, the AUC released an announcement which relayed much of the information in Bulletin 2020-08. However, the announcement also noted that the AUC has already scheduled a meeting with utilities, competitive retailers, gas co-operatives, rural electrification associations, etc. so all the necessary details can be put in place right away. The AUC also noted that, in the past, the AUC had implemented focused programs that were put in place in locations hit by disaster, including following wildfires in High Level and Fort McMurray.

Further, the AUC indicated that Alberta's emergency situation and the deferral program would be monitored over the next quarter to determine if it should be extended or modified.

Statement from AUC Chair Mark Kolesar Regarding COVID-19 (AUC 2020-03-27-Announcement)

On March 27, 2020, the AUC Chair, Mark Kolesar, made a statement regarding COVID-19. Mr. Kolesar extended his thanks to everyone working hard in the utility sector to keep essential services available. He noted that now more than ever, the AUC is committed to ensuring Albertans continue to receive safe and reliable utility service by working with utility providers and assisting the government.

Mr. Kolesar indicated that he had been in discussions with utility companies and the electric system operator to see what activities must be prioritized, how shared responsibilities would be approached and, most importantly, to ensure coordination on critical initiatives. Mr. Kolesar noted that the AUC is leading the government's billing deferral initiative to ensure help is available for those in need. Further, he noted that the AUC is re-evaluating its work efforts in light of the crisis. For example, the AUC has taken the extraordinary step to pause the enforcement of specified penalties of utility billing infractions to allow the utilities to focus on priority work.

Suspension of Specified Penalties Program for Self-Reported Contraventions (AUC Bulletin 2020-10)

On March 27, 2020, the AUC announced that it was introducing measures to ensure Alberta's electric and natural gas utilities, service providers and retailers can focus their resources on putting measures in place to respond to the Alberta Government's utility payment deferral program. The AUC indicated it is exercising its regulatory discretion under *AUC Rule 032: Specified Penalties for Contravention of AUC Rules*, and putting in place the following measures:

1. no new notices of specified penalty for any contraventions that arose prior to March 18, 2020, will be issued during the 90-day deferral period from March 18 to June 18, 2020. Any notices of specified penalty issued prior to March 18, 2020, will continue in effect. Any notices of specified penalty issued prior to March 18, 2020, will continue in effect.

2. after June 18, 2020, for any self-reported contraventions that arose prior to March 18, 2020, the AUC will only consider issuing notices of specified penalty for contraventions that resulted in disconnections of a customer's site in error if that customer's site was disconnected for a period in excess of 24 hours. A notice of specified penalty will not be issued for any other self-reported contraventions.

3. after June 18, 2020, for any self-reported contraventions that arise during the 90-day deferral period, the Commission will only consider issuing notices of specified penalty for contraventions that resulted in disconnections of a customer's site in error if that customer's site was disconnected for a period in excess of 24 hours. A notice of specified penalty will not be issued for any other self-reported contraventions.

AUC Supports Market Surveillance Administrator Action Regarding Compliance With Reliability Standards (AUC Bulletin 2020-12)

On March 31, 2020, the AUC announced it supports the Market Surveillance Administrator ("MSA")'s action regarding compliance with reliability standards. On March 30, 2020, the MSA announced a relaxation on enforcement of certain Alberta Electric System Operator and market participant reliability standards for the period March 1, 2020, to July 31, 2020. The AUC indicated this action and others like it allow industry to prioritize resources in order to respond to the COVID-19 crisis most effectively.

***Direct Energy Regulated Services Application for True Up of the 2019 Interim Rates for the Default Rate Tariff and the Regulated Rate Tariff*, AUC Decision 25341-D01-2020**

Rates - Electricity - True-Up Application

In this decision, the AUC considered an application (the "Application") from Direct Energy Regulated Services ("DERS") to true-up its 2019 interim rates for the default rate tariff ("DRT") and the regulated rate tariff ("RRT"). The AUC approved the true-up amounts, to be in place from May 1, 2020, to July 31, 2020. The AUC also found that DERS had complied with an outstanding direction from Decision 23986-D01-2018.

AUC Findings

Compliance with Direction from Decision 25255-D01-2020

This Application was filed in response to the following direction included in Decision 25255-D01-2020:

> DERS operated under Commission-approved interim rates for all of 2019, with the interim rates approved in Decision 23989-D01-2018. These interim rates have to be trued up to the final rates for 2019 approved in this decision. The Commission directs DERS to file a separate application for the true-up of each of the 2019 DRT and RRT rates approved in this decision for the period from January 1, 2019, to December 31, 2019, after DERS has completed billing on interim rates for 2019.

The AUC found that by filing the Application in this proceeding, DERS complied with the direction in paragraph 13 of Decision 25255-D01-2020.

True-up Amounts

Based on its review of the calculations provided by DERS, and the explanations provided by DERS regarding the calculations, the AUC found that DERS correctly calculated each of the true-up amounts. The AUC, therefore, approved the true-up amounts, set out in Table 1:

Table 1. True-up amounts for the period from January 1, 2019, to December 31, 2019

Service charges	True-up amount ($000)
RRT non-energy	
Rate class E1: residential	1,949.5 collection from customers
Rate class E2: small general	393.8 collection from customers
Rate class E3: large general	30.3 collection from customers
Rate class E4: oilfield	6.6 collection from customers
Rate class E5: farm	588.4 collection from customers
Rate class E6: lighting	22.9 collection from customers
Rate class E7: irrigation	1.3 collection from customers
RRT non-energy: net for DERS	2,992.9 collection from customers[8]
DRT non-energy	
Rate class G1: general service	2,216.8 collection from customers
Rate class G3: large use service	28.8 refund to customers
Rate class G5: irrigation service	1.4 collection from customers
DRT non-energy: net for DERS	2,189.4 collection from customers
DRT return margin	762.9 collection from customers
DRT certain energy costs	619.5 collection from customers
DRT labour costs related to gas procurement	69.3 collection from customers

Proposed Methods and Timing to Collect/Refund the True-Up Amounts

The AUC approved the methodologies and the timing that DERS proposed to collect the true-up amounts for the DRT return margin, the DRT certain energy costs and the DRT labour costs related to gas procurement, as follows. The AUC accepted the proposal to collect these true-up amounts through the gas cost flow-through rates ("GCFR") because the associated interim rates were also included as part of the GCFR. The current proposal was also consistent with the proposal the AUC approved as part of DERS' last two interim rates true-up applications.

With respect to the rider methodology and the timing that DERS proposed to deal with the true-up amounts for the RRT and the DRT non-energy interim rates, the AUC found that the methodology and timing are reasonable. The rider methodology was consistent with the methodology that the AUC approved as part of DERS' last two interim rates true-up applications. The AUC acknowledged DERS' analysis, which indicates that for each of the three months from May 2020 to July 2020, the proposed riders for the residential customers would result in increases to the average monthly gas bill ranging from 2.3 percent to 2.9 percent, and increases to the average monthly electricity bill ranging from 5.3 percent to 5.9 percent. The AUC considered that increases in this range are not indicative of rate shock.

Non-Energy Rider Amounts for the DRT and the RRT

The AUC found that DERS had correctly calculated each of the non-energy rider amounts for the DRT and the RRT. The AUC, therefore, approved the rider amounts as set out in Table 2:

Table 2. Proposed riders to be in place for the RRT and DRT non-energy customers, from May 1, 2020, to July 31, 2020

Service charges	Proposed rider amount ($/day/site)
RRT non-energy	
Rate class E1: residential	0.284 charge to customers
Rate class E2: small general	0.440 charge to customers
Rate class E3: large general	1.356 charge to customers
Rate class E4: oilfield	0.454 charge to customers
Rate class E5: farm	0.340 charge to customers
Rate class E6: lighting	0.061 charge to customers
Rate class E7: irrigation	0.292 charge to customers
DRT non-energy	
Rate class G1: general service	0.049 charge to customers
Rate class G3: large use service	0.487 credit to customers
Rate class G5: irrigation service	0.016 charge to customers

Compliance with Direction from Decision 23986-D01-2018

The AUC reviewed the information filed by DERS regarding the actual amounts collected or refunded that related to each of the true-up amounts approved in Table 1 of Decision 23986-D01-2018 and found that DERS complied with the direction from paragraph 13 of Decision 23986-D01-2018 by providing the information directed. The AUC reviewed the differences between the actual and approved amounts collected/refunded for each customer rate class for the DRT and the RRT and found that none of the differences were significant or material enough to warrant a further true-up.

***ENMAX Energy Corporation 2017-2020 Regulated Rate Option Non-Energy Tariff*, AUC Decision 23752-D01-2020**

Rates - RRO Non-Energy Tariff

In this decision, the AUC considered the 2017-2020 regulated rate option ("RRO") non-energy tariff application (the "Application") filed by ENMAX Energy Corporation ("EEC"). The main issue in the Application was the new methodology for allocating billing and customer care ("B&CC") costs, which the AUC denied. The AUC made findings on other matters such as inflation, site count, bad debt, hearing cost reserve account, terms and conditions and the proposed amendment and reopener provision. The AUC directed EEC to submit a compliance filing by May 1, 2020, incorporating the AUC's directions.

<u>Cost Allocation Methodology</u>

EEC proposed a new allocation methodology to allocate B&CC costs commencing in January 2018. The new allocation method would use the following drivers to allocate B&CC expenses: interaction reason record handle time ("IRR handle time"); "contract account proportion"; and proportion of total direct B&CC operating expenses. The new allocation methodology would have two steps, a primary allocation and a secondary allocation.

The primary allocation would apply the B&CC costs to all customer categories. Customer categories that comprise multiple service categories would require a secondary allocation to determine the costs associated with each individual service category.

The AUC noted it had an underlying concern with the primary allocation results for single-service category customer groups being used to allocate the

B&CC costs of multiple service category customer groups, particularly the RRO and municipal customer category. The AUC's concern was related to the relatively small proportion of B&CC costs associated with single-service category customers being used to allocate the majority of B&CC costs that reside in the multiple service category customer groups. The AUC found that sufficient evidence was not provided to alleviate the AUC's concern.

The AUC noted it had no confidence in the results of the analysis supporting the secondary allocation and the assumption on which the secondary allocation was based. Consequently, the AUC found it was unable to approve EEC's proposed secondary allocation methodology.

The AUC considered the shortcomings that needed to be analyzed further, including the reliability of the IRR handle time data given the decline in RRO site counts, adjustments to IRR handle time to account for issues that were the subject of the Market Surveillance Operator's investigation, and whether EEC's analysis on the allocation of costs to multiple service categories was equal to the relative amount of interaction time to customers with only one service category.

The AUC found that based on these shortcomings, EEC did not establish that its methodology would result in just and reasonable RRO rates. As a result, the AUC rejected the new B&CC allocation methodology. The AUC directed EEC to use its current B&CC cost allocation methodology and file the resulting cost allocations and corresponding rates in the compliance filing to this decision.

Inflation

To develop its 2020 revenue requirement, EEC used a 2.0 percent inflation factor based on the Alberta real Gross Domestic Product ("GDP") growth rate from the Calgary and Region Economic Outlook.

The AUC noted that, as a forecast instrument, it is conceivable that the Alberta real GDP growth rate captures the aggregate net effect on revenue requirement adequately. Generally speaking, however, it is likely that a quantity index, like the Alberta real GDP growth rate, would not be as good an estimator for the prospective change in per unit costs of inputs under general, changing economic conditions; a theoretically more sound choice for such an estimator is likely to be a price index under the same general and changing economic conditions.

The AUC found that EEC had not established a sufficient basis for changing to the Alberta real GDP growth rate as an escalator in the determination of its forecast revenue requirements. The AUC directed EEC, in its compliance filing, to base its 2020 labour escalation rate on the Alberta average wage rate increase for all industries forecast in the Fall 2019 Calgary and Region Economic Outlook, to a maximum of 2.0 percent. The AUC directed EEC to use the Alberta consumer price index estimate as its non-labour inflation factor from the Fall 2019 Calgary and Region Economic Outlook, to a maximum of 2.0 percent, as the inflation factor in determining its forecast revenue requirement for 2020.

RRO Site Counts

A "site" is defined by EEC as a single service received by a customer so that a single customer may consist of more than one site. The RRO site count is the total number of residential or commercial customer sites in the Calgary area that receive RRO service from EEC. EEC included the actual RRO site counts for 2017 and 2018 and used a forecasting methodology to determine the 2019 and 2020 forecast RRO site counts.

The AUC considered that updating the site count data to produce site count values for 2019 and 2020 that reflect the most up-to-date information was something that could be done fairly easily as part of the compliance filing. The AUC, therefore, directed EEC as part of the compliance filing, to update the RRO monthly site count data for 2019 and 2020 by using actual data for all months where such data is available, and to incorporate this actual data in deriving the forecast for the remaining months.

Non-Energy Revenue Requirements

Bad Debt

EEC's bad debt cost comprises debt resulting from billed amounts that are uncollectable from specific customers. Bad debt as a percentage of revenue is based on actuals for 2017 and 2018, and forecasts for 2019 and 2020.

EEC noted that bad debt increased in 2018 due to higher than forecast energy prices compared to 2017 and a one-time increase for credit loss allowance that resulted from a change to the impairment methodology for accounts receivable. EEC submitted that this change was required by the International Financial Reporting Standard 9 ("IFRS

9"), which was effective January 2018, and replaced the International Accounting Standard 39 ("IAS 39").

The AUC found that EEC did not provide sufficient reasons to change its accounting treatment of bad debt, in simply stating that it was required to adopt IFRS 9. EEC did not adequately explain why the change to IFRS 9 was required for RRO service or how it would benefit EEC and its customers. The AUC directed EEC in the compliance filing, to continue to use its current methodology for calculating bad debt, and to revise its bad debt forecast accordingly.

Hearing Cost Reserve Account

The proposed hearing cost reserve account funding related to EEC's anticipated terms and conditions amendment application, *AUC Code of Conduct* reviews and assessments, and other regulatory proceedings and costs. In addition, EEC proposed to use funds from the hearing cost reserve account to offset the costs of an audit directed by the AUC.

The AUC noted that the hearing cost reserve account is a way to ensure that hearing costs are recovered in rates in a fair and equitable manner. The AUC approved the continuation of the hearing cost reserve accounts for 2017-2020 for EEC's RRO non-energy tariff. The AUC noted that customers should only pay the AUC-approved costs for participation in regulatory proceedings, and the use of hearing cost reserve accounts permits the recovery of any AUC-approved regulatory costs that parties incur during these proceedings.

Terms and Conditions

The AUC reviewed the changes to EEC's terms and conditions, which incorporated the requirements in section 3.4.2 - Service Guarantees of *Rule 003: Service Standards for Energy Service Providers*. In particular, the AUC reviewed the definition of "Permissible Disconnection Period," the changes to section 8.5 - Disconnection Other Than For Safety Reasons, and the changes to section 8.7 - Service Guarantee. The AUC found that the proposed changes to these sections accurately reflect the requirements of Section 3.4.2 of *Rule 003*. The AUC, therefore, approved EEC's terms and conditions.

Amendment and Reopener

EEC stated that material changes in applicable law or policies or rules having the effect of law may occur and may result in additional material costs or benefits not provided for in its non-energy tariff. EEC, therefore, requested that the AUC approve a non-energy tariff reopener provision by which affected parties, including EEC, may respond to any of these material circumstances.

The AUC found that EEC had not demonstrated the need to include a reopener provision in its non-energy RRO tariff. EEC could not provide any past examples where it would have applied to use such a reopener provision if one had been in place. Additionally, while EEC provided some recent examples of potential changes that may affect the RRO, these examples were not described in sufficient detail, and EEC did not explain how these examples could result in additional material costs or benefits not provided for in the 2017-2020 non-energy tariff. Consequently, the AUC denied EEC's request that the AUC approve a non-energy tariff reopener provision.

Order

The AUC ordered that EEC submit a compliance filing, responding to the orders and directions of the AUC as set out in this decision by May 1, 2020.

***ENMAX Energy Corporation 2019-2022 Energy Price Setting Plan*, Decision 24721-D01-2020**
Rates, Energy Price Setting Plan

In this decision, the AUC considered an application from ENMAX Energy Corporation ("EEC") in which the regulated rate option ("RRO") provider requested approval of its 2019-2022 energy price setting plan ("EPSP"). EEC utilizes a competitive auction methodology for procuring energy and for establishing the energy charge to be paid by its RRO customers. The AUC found that the proposed auction design satisfies the requirements set out in the *Regulated Rate Option Regulation* ("*RRO Regulation"*). The AUC did not approve all aspects of the 2019-2022 EPSP, and EEC is required to file a compliance filing by no later than April 30, 2020.

Background

EEC is an RRO provider that is regulated by the AUC. EEC provides RRO service in the ENMAX Power Corporation service area, which is the city of Calgary.

EEC received AUC approval of its 2016-2018 EPSP in Decision 20448-D01-2017. An important feature of that EPSP in the determination of energy rates was the block procurement process that EEC uses to purchase electricity in the forward markets. In its 2019-2022 EPSP application EEC proposed to depart from its block procurement methodology and adopt a descending clock auction process to procure its energy. This new procurement process involves simultaneous auctions for three different types of energy products: peak blocks, flat blocks and full-load strips. EEC maintained that these auctions would produce prices that can be used to determine a just and reasonable market-based value for commodity risk compensation ("CRC"), in addition to providing contracts for the provision of electricity that will ensure that its forecast loads can be met.

Legislative Framework

The AUC noted that it must evaluate the auction process, pricing and the terms of the EPSP subject to the governing provisions of the *RRO Regulation*.

EEC's Proposed EPSP

EEC retained an independent energy market expert, NERA Economic Consulting ("NERA"). NERA specializes in energy markets and the design and implementation of competitive auctions. In 2018, it assisted EPCOR Energy Alberta GP Inc.'s ("EPCOR's") transition to an auction-based procurement model that was approved by the AUC in Decision 22357-D01-2018.

EEC indicated that its proposed EPSP was substantially similar to EPCOR's 2018-2021 EPSP but was modified slightly to accommodate for such things as EEC's different RRO load volume and RRO load characteristics. Compared to EPCOR's RRO load, EEC's RRO load volume is one-third the size of EPCOR's and the shape of its load is different.

The four modifications proposed for EEC's EPSP that differ from EPCOR's 2018-2021 EPSP include:

- procuring 40 percent of its RRO obligation as full-load product rather than 50 percent;
- hosting three auctions instead of four auctions;
- having the discretion to purchase one extra peak block in auctions where there would otherwise be fewer than two peak blocks procured; and
- setting monthly targets for peak and full-load products based on the target for flat products instead of the target for peak products.

EEC submitted that an improvement proposed for EEC's EPSP, when compared to the design of EPCOR's 2018-2021 EPSP, includes holding a supplemental phase after the closing round to gather exit prices for retained withdrawal units.

EEC also stated that its proposed EPSP would rely on market forces to determine the energy charge through the use of a descending clock auction process. Specifically, EEC submitted that market forces would determine competitive rates through the simultaneous procurement of flat, peak and full-load products in the auction process.

Descending Clock Auction Proposal

Sufficiency of the Pool of Suppliers and EEC's Volumes

The AUC accepted the submissions of EEC and NERA that there is a pool of suppliers for full-load products in Alberta, noting that EPCOR has been able to procure its load through its competitive auctions, which include a full-load product. It made further note of NERA's evidence, which concluded that "the Alberta market is reasonably capable of supporting the procurement of a Full-Load product by ENMAX Energy in addition to the procurement of Full-Load products by EPCOR under its current EPSP."

Size of EEC's RRO Volumes and Market Interest in Auctions

The AUC acknowledged interveners' concerns regarding the size of EEC's RRO volumes and agreed that it could not be assumed that full-load suppliers who participate in EPCOR's auctions will automatically participate in EEC's auctions. It would have been preferable for EEC to canvas suppliers to ensure there is interest in EEC's smaller RRO volumes.

However, the AUC further noted that the degree of participation could not be identified conclusively until an EEC descending clock auction process is implemented. The AUC found that there was sufficient evidence to support the view that EEC's descending clock auctions are likely to be supported by the Alberta market. The AUC also made note of important safeguards built into EEC's descending clock auction process, including a competitiveness assessment at the end of each auction, backstop supply, and a reopener provision in the EPSP.

Requirement to Consider Alternative Procurement Methodologies

The Utility Consumer Advocate ("UCA") submitted that EEC failed to consider alternative procurement options that may result in more competitive and advantageous pricing for EEC's RRO customers.

The AUC did not agree that EEC was obligated to provide alternative procurement options. It noted that the *RRO Regulation* defines the obligations required by an applicant proposing an EPSP to have its application be successful. How an applicant dispenses its obligation to demonstrate that the requirements of the *RRO Regulation* have been met is up to the applicant.

Commodity Risk Compensation

Higher RRO Rates

The UCA submitted that setting monthly RRO rates based on the price of the full-load product will not result in just and reasonable rates. It compared the prices of competitive retailers offering energy on a load-following, fixed price basis to the price for EPCOR's full-load product obtained in the descending clock auctions from April 2019 to December 2019. It determined that EPCOR's full-load product was consistently higher than competitive retailer products such as ENCOR by EPCOR and EEC's EasyMax.

The AUC found that the UCA's comparison of EPCOR's rates to the rates of competitive retailers did not demonstrate that EPCOR's risk compensation is too high. It made note of EEC submissions that competitive retailers do not face the same restrictions as RRO providers and may employ strategies to mitigate risks that are not available to RRO providers because competitive retailers can contract for longer-term products.

The AUC acknowledged that EPCOR's risk compensation under its current EPSP has been larger than the risk compensation under EEC's and Direct Energy Regulated Services' administrative method over the initial months of operation. However, this does not mean that EPCOR's risk margin is too high or that the calculation of EPCOR's market-based risk margin does not result in just and reasonable rates under EPCOR's EPSP.

Profit and Loss Neutrality

EEC's proposed CRC was calculated in the same way as that which was approved for EPCOR. In the decision on EPCOR's 2018-2021 EPSP, the AUC stated with respect to EPCOR's CRC methodology:

> … the Commission considers that the resulting prices for the full-load product and the fixed block products obtained through competitive descending clock auctions will reflect current expectations for the forward market conditions, including the risk associated with those expected forward market conditions. The resulting CRC will be transparent, and it will reflect the level of risk aversion of the successful auction participants. The Commission considers that this approach is reasonable in calculating a CRC for the 2018-2021 because of the expectation that this will set a CRC based on the competitive market prices

For the same reasons, the AUC accepted EEC's proposed market-based CRC, finding that the calculation of it using the difference between the weighted average price of the full-load product and the weighted average price of fixed block products procured through the auctions is in accordance with the *RRO Regulation*.

Overcompensation for Risk

The AUC noted that in assessing whether the difference between full-load strip prices and the weighted average price of peak and flat blocks is a reasonable estimation of the risk compensation for EEC, two pieces of information are required: first, whether full-load suppliers face the same risks as EEC; and second, whether full-load suppliers and EEC have the same or similar levels of risk aversion.

The AUC noted that there was an absence of evidence to inform a determination of the relative risk preferences of EEC and full-load suppliers.

It also found that there was insufficient evidence to determine conclusively that full-load suppliers face less risk than EEC. The AUC placed more weight on the opinion evidence of EEC's expert witness, NERA, that full-load suppliers will face less risk than EEC, and found that, as long as EEC's auctions are competitive, the resulting auction prices can be used to determine a reasonable, market-based CRC for EEC.

Return and Risk Compensation

The CCA submitted that it is possible that a CRC inferred from full-load products may include a return margin in addition to compensation for assuming commodity risk.

The AUC stated that competitive forces within EEC's auctions would lead to the removal of any excess return contained within the bids of full-load strip suppliers. The AUC found that there was insufficient evidence before the AUC to conclude that the return will be inflated as posited by the CCA.

Load Forecasting Methodology

The AUC approved EEC's load forecasting methodology, noting that it is the same methodology that EEC uses in its current EPSP.

Descending Clock Auction Parameters and Auction Format

Auction Parameters and RRO Load Procurement Split

The AUC found that EEC's proposal to acquire flat volume blocks, peak volume blocks and a full-load product as part of its 2019-2022 EPSP was well supported.

The AUC noted that the success of EPCOR's auctions has demonstrated that the concept of procuring electricity through descending clock auctions is practicable in Alberta.

The AUC also accepted NERA's recommendation of three auctions per delivery month with 40 percent of the RRO load to be procured through the full-load product and 60 percent through fixed block products. Based on NERA's evidence that procuring 40 percent of the RRO load through the full-load product will lead to fewer auctions where the quantity of any one product falls below a threshold of two units, the AUC agreed that supplier interest would be improved under this arrangement when compared to having 50 percent RRO load being procured through the full-load product.

In the scenario where EEC needs to procure an additional peak product block for a delivery month, the AUC directed EEC to exclude the procurement cost of the additional block in the base energy charge and convey this in its monthly filings. The AUC stated this additional peak block should not be used in the calculation of the monthly energy charge because the monthly energy charge should be based on the price of the full-load product. The AUC also stated that the additional peak product block will be treated the same as the other peak blocks and will be used to calculate the CRC.

Auction Format and Monitoring

The AUC found that EEC's proposed use of a descending clock auction format was sufficiently supported, and approved EEC's proposed use of a descending clock auction format for its 2019-2022 EPSP.

The AUC found some merit in the CCA's and the UCA's concerns relating to EEC's smaller RRO volumes and potential for market dominance. The AUC directed EEC to submit a proposal for an auction monitoring report and process in its compliance filing.

Recurring Cost Items

The AUC considered that Natural Gas Exchanged ("NGX") collateral costs, NGX trading charges and transaction fees and AESO trading charges, AESO collateral costs, and retailer adjustment to market costs are legitimate expenses associated with the provision of RRO service by EEC. The AUC approved the inclusion of these charges and fees, expressed in $/MWh, as part of the monthly energy charge under EEC's 2019-2022 EPSP.

The AUC also considered that uplift charges are a legitimate expense associated with the provision of RRO service, and accepted EEC's proposed methodology for calculating uplift charges.

The AUC found that external EPSP development and regulatory costs should be part of the energy charge, including costs associated with the development and deployment of the auction software and platform. The AUC noted that EEC had not received an estimate from NGX regarding the time and cost associated with developing and deploying the auction software, and directed EEC to provide an estimate of these costs and lead time in a compliance filing.

Monthly Energy Charge Calculation

The AUC noted the monthly energy charge, expressed in $/MWh and billed to residential and commercial customers on a cents/kWh basis, will consist of the base energy charge (which includes CRC), the backstop charge (when applicable), the reasonable return compensation, and each of the recurring cost items. The AUC found EEC's proposed methodology and calculations to determine the base energy charge reflects the components of the monthly energy charge, and are acceptable.

Distribution Line Losses and Unaccounted-for Energy

The AUC found EEC's incorporation of distribution line losses and unaccounted-for energy in the monthly energy rate calculations were acceptable.

Information to Be Included in Monthly Filings

The AUC agreed with EEC's proposal to remove the percentage of EEC's customers who are enrolled in the RRO from its monthly filings. This information is unnecessary, and this will eliminate the need for confidential filing of the rate calculation workbook. The AUC found other items that EEC proposes to include in its monthly filings to be substantially similar to what EEC files under its current EPSP.

Backstop Mechanism

The AUC found EEC's proposal to have URICA Energy Management Corporation ("URICA") administer a request for quotation ("RFQ") process for EEC's backstop mechanism was reasonable.

The AUC found that the ongoing maintenance of the confirmed backstop supplier list is necessary to ensure the timely operation of the backstop mechanism. The AUC noted that $2,500 is an acceptable amount to be paid to URICA to provide that ongoing service. The AUC also found a $5,000 backstop fee reasonable for URICA in EEC's energy charges, for those rare months in which the backstop mechanism is likely to be triggered.

The AUC noted that in the event that the backstop mechanism is triggered, EEC and URICA must provide a summary report to the AUC providing details relevant to the backstop supply of energy as part of the monthly filing for RRO rates. It directed EEC to amend its EPSP, as part of its compliance filing, to reflect this finding.

The AUC shared the UCA's concern with the discretion that EEC proposes to provide to URICA in determining those confirmed backstop suppliers who will receive the backstop RFQ if backstop supply is required. The AUC found that the RFQ should be sent to all confirmed backstop suppliers to obtain as many supplier responses as possible, and directed EEC to amend its EPSP, as part of its compliance filing, to reflect this finding.

Reasonable Return

EEC applied to update its reasonable return based on 2018 revenue information, resulting in a new reasonable return of $2.63/MWh, from $2.44/MWh. EEC also proposed to update this number in July of each year for the term of the proposed EPSP, based on its annual Rule 005 filings to the AUC.

The AUC approved the formula included in EEC's illustrative energy charge model to calculate EEC's reasonable return amount. It found that the proposal to update the reasonable return each year and reflect the updated reasonable return figure starting with the energy rates for July of that year is reasonable because this ensures that the calculated reasonable return will be based on the most up-to-date information that is available each year.

The AUC directed EEC to include the applicable pre-tax reasonable return rates in $/MWh in future Rule 005 filings and to also provide the corresponding energy figures in those filings.

***FortisAlberta Inc. Municipal Franchise Fee Amendment for 3 Municipalities*, Decision 25425-D01-2020**

Rates

In this decision, the AUC approved amendments to the Municipal Franchise Fee Riders as follows:

Municipality	Current Franchise Fee	Increase % for 2020	Franchise Cap
City of Airdrie	17%	18%	20%
City of Camrose	10%	13%	20%
Town of Wainwright	9%	11%	20%

CANADA ENERGY REGULATOR

Nova Gas Transmission Ltd System Rate Design and Services Application, **CER Decision RH-001-2019**

Rates - Gas Pipeline - Rate Design

In this decision, the CER considered an application (the "Application") from Nova Gas Transmission Ltd. ("NGTL") for approval of a new rate design methodology and terms and conditions of service for the NGTL System. The CER approved the Application. However, the CER found that there was potential for further improvements in NGTL's rate design and services. To inform future toll and tariff discussions, the CER provided directions on additional steps NGTL must take and timelines for compliance.

Background

The NGTL System is an extensive natural gas transmission system comprised of approximately 24,000 kilometres of pipeline and associated compression and other facilities in Western Canada. The NGTL System transports natural gas produced in Alberta and British Columbia from the Western Canada Sedimentary Basin ("WCSB"). Natural gas produced from the WCSB competes in the North American gas market on many fronts.

Legislative Framework

Section 62 of the *National Energy Board Act* (the "*NEB Act*")states:

> 62. All tolls shall be just and reasonable and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.

Section 67 of the NEB Act states:

> 67. A company shall not make any unjust discrimination in tolls, service or facilities against any person or locality.

On 28 August 2019, the *Canadian Energy Regulator Act* ("CER Act") came into force, replacing *the NEB Act*. The National Energy Board ("NEB") was succeeded by the CER. Section 36 of the transitional provisions associated with the *CER Act* states that applications pending before the NEB prior to coming into force of the *CER Act* are to be taken up by the CER and continued in accordance with the *NEB Act*. As the Application was pending before the NEB prior to 28 August 2019, the Application was taken up by the CER and continued in accordance with the *NEB Act*.

The Application

The Application was supported by a contested Settlement (the "Settlement"). NGTL also sought approval of two associated matters that did not form part of the Settlement: (1) a surcharge formula to be paid by FT-R shippers on the North Montney Mainline ("NMML"); and (2) amendments pertaining to Firm Transportation – Points to Point ("FT-P") service.

The Settlement

Whether Settlement Treated as a Package

The CER found that the Settlement negotiation process would be undermined if the CER were to freely impose selected changes at its discretion. The CER stated that the Settlement submitted by NGTL should be treated as a package and approved the Settlement on that basis.

Postage Stamp FT-D2 and FT-D3 Rates

Group 2 Delivery Points ("FT-D2") and Group 3 Delivery Points ("FT-D3") rates are based on a postage stamp methodology. FT-D3 is priced at a 20 percent premium to the FT-D2 rate. The parties to the Settlement agreed to not depart from the current postage stamp methodology for FT-D2 and FT-D3 services.

The CER approved the postage stamp methodology for FT-D2 and FT-D3 rates. However, the CER directed NGTL to initiate an additional evaluation of potential cross-subsidization between delivery points and further consultation with the Tolls, Tariff, Facilities and Procedures Committee ("TTFP") regarding the Major Market proposal proposed by ATCO Gas ("ATCO") in this proceeding. The CER also directed NGTL to file a report containing an assessment of the current FT-D2 and FT-D3 cost allocation methodology, an assessment of alternate methodologies, the consultation process NGTL undertook and the next steps to rectify any unreasonable cross-subsidization.

Metering Charge

The NGTL net transportation revenue requirement consists of two components: a transmission component and a metering component. The CER found that the metering charge, as included in the Settlement, was acceptable. However, the CER found that additional analysis was required on this matter, as well as further TTFP consultations.

Unit Cost Index

NGTL currently uses a Unit Cost Index ("UCI") in FT-R rates. Under NGTL's proposed rate design, FT-D rates would also be derived using a delivery UCI. The UCI is a comprehensive determination of the relative unit cost for transportation for various pipe diameters, incorporating economies of scale derived from historical acquisition costs for each pipe size, and considers other factors, such as compression costs and Operations and Maintenance ("O&M") costs. The CER did not find, as suggested by ATCO, that small diameter pipe is being unreasonably over-allocated costs within the UCI methodology. The CER noted ATCO's acknowledgement that NGTL's evidence that pipe integrity costs are generally not correlated to pipeline diameter lessened ATCO Gas's concerns on this issue.

Length of Contract Term and Term-Up Provision

Under the Settlement, the default minimum contract term in constrained areas of the System is an eight-year total term with a minimum primary term between two years and five years. The CER approved the minimum contract term length and no term-up provision.

Intra-Basin / Export Shipper Contract Terms

The CER found that differences in contract term length between Group 1 Delivery Points are ("FT-D1") and intra-basin shippers were not unjustly discriminatory. NGTL's evidence demonstrated that the discrepancy arises from the practical need to allocate capacity differently for intra-basin versus export delivery points.

Rural Gas Interconnections

Rural gas interconnections ("Taps") allow rural end users with an average daily demand of less than 1 TJ and peak daily demand of less than 5 TJ to access the NGTL System. The CER accepted NGTL's commitment in the Settlement to hold discussions with a view to codifying in the NGTL's Tariff the existing practices pertaining to Taps.

Default Tolling of Extensions

The CER questioned the value and appropriateness of the default rolled-in provision, as drafted in the Settlement. The CER noted, however, that no provision could relieve or prevent the CER from exercising its regulatory oversight of a tolling methodology. The CER, therefore, interpreted the default methodology provision as solely a commitment by NGTL to its shippers to use rolled-in tolling as a starting point when beginning discussions on future projects. Tolling treatment of future extension projects, the CER found, must be addressed on a case-by-case basis.

Flow Data and Toll Filings

The CER found that the information in Table 1.5-9 in response to NEB IR No.1.5 is relevant for the future interim and final tolls applications that implement the approved rate design. Table 1.5-9 provided distance and diameter data for NGTL's proposed East Gate delivery tolling. The CER noted this information provides transparency regarding allocation factors, which can change over time and can have a significant impact on the resulting rates. The CER, therefore, directed NGTL to include the same type of information in all future filings for interim and final tolls under the approved rate design. The CER also acknowledged NGTL's commitment to use data for NGTL System flows from the most recent months of February and July to determine the FT-D paths.

The CER indicated it expects NGTL to implement the proposed rate design within a reasonable time frame but did not impose any specific direction on implementation timing. However, the CER directed NGTL to file with the CER, at the time of its final 2020 rates application, its updated NGTL System Tariff in its entirety incorporating the revisions approved in this decision and the final 2020 rates, tolls and charges that NGTL is seeking the CER's approval to implement.

FT-P Amendments

NGTL applied for additional FT-P amendments that did not form part of the Settlement:

(a) the FT-P adjustment would increase from 4 cents/Mcf/d to 10 cents/Mcf/d, and

(b) an FT-P Price Point D would be implemented with a discount set at 85 percent of the FT-P Price Point A when three eligibility criteria are met.

These measures were uncontested and approved by the CER.

North Montney Mainline Tolling Methodology

The Settlement specified that shippers on the NMML would be subject to a surcharge in addition to the otherwise applicable rates under the NGTL rate design. The specific methodology to be applied to NMML shippers, including the NMML Surcharge Formula and Surcharge Coefficient, was included in NGTL's Application. However, it did not form part of the Settlement.

The CER approved the NMML Tolling Methodology, including the NMML Surcharge Formula and the proposed Surcharge Coefficient of 0.3. However, the CER imposed a condition on NGTL should gas transported on the NMML be delivered to new large volume markets and certain accounting requirements specific to the NMML.

Broader Considerations

The CER indicated it was concerned with NGTL ensuring appropriate cost accountability for shippers requiring receipt extensions and the capability of the distance of haul methodology to recognize future flow patterns. Accordingly, the CER directed NGTL to file ongoing information to enable transparency and accountability to the CER and shippers over time.

The CER stated that fundamental risk is not materializing on the NGTL System at this time but remains a long-term risk. Continuing the practice of regularly updating depreciation assumptions and providing revised studies reduces the future risk of undepreciated facilities. The CER, therefore, directed NGTL to file a depreciation study in the second-half of 2023, including certain capital spending and capital maintenance information.

In the NEB's previously issued North East British Columbia Decision (the "NEBC Decision"), the NEB directed NGTL to file certain information with its next toll filing regarding NGTL's policies affecting capital spending for system expansions, NGTL's depreciation policy and practices, and NGTL's tolling methodology and tariff provisions. In the Application, NGTL put forth a mix of the existing rate design methodology with some proposed amendments. The CER found that the proposed changes were generally responsive to the NEBC Decision as they introduced stronger cost accountability for receipt shippers. However, the CER directed NGTL to file, and continue to make available certain information for the benefit of the CER and interested parties.

The CER acknowledged NGTL's position regarding the production of a five-year toll forecast to assess the cumulative impacts of its capital spending program. Instead of a five-year toll forecast, the CER directed NGTL to extend the narrative accompanying the unit cost of transportation data in its Annual Plan.

CER Decision

The CER approved the Application. The CER found that the Settlement would result in tolls that are just and reasonable and not unjustly discriminatory. The CER found that the Settlement is consistent with the cost-based/user-pay principle and promotes proper price signals in alignment with the economic efficiency principle. Further, the CER found that the Settlement complied with the NEB's Settlement Guidelines. Overall, the proposed amendments represent an improvement in aligning tolls with the underlying costs of providing service.

Notwithstanding its approval of the Application, the CER indicated it sees a need for continued improvements in NGTL's rate design and services. Throughout the decision, the CER provided direction to NGTL regarding additional obligations to disclose information and facilitate discussions among the TTFP and interested parties regarding areas of concern. The CER indicated it expects a pipeline company to share sufficient information with shippers on an ongoing basis. Shippers should be able to obtain information from a pipeline company during negotiations without having to resort to the information request process of a hearing.