ISSUE:
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DECISIONS

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

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ANNOUNCEMENTS

Changes to Climate Change Regulations
Specified Gas Emitters Regulation – Climate Change

On June 25, 2015, the Minister of Environment announced that the *Specified Gas Emitters Regulation* ("*SGER*") will be extended out until 2017. The *SGER* was set to expire on June 30, 2015. Changes were also announced for the *Specified Gas Reporting Regulation*, the *Administrative Penalty Regulation*, and the *Climate Change and Emissions Management Fund Administration Regulation*.

The changes were made pursuant to Orders in Council 159/2015, 160/2015, 161/2015 and 162/2015 (the full text of the changes are provided in the links). The extensions maintain the current compliance framework for greenhouse gas emissions, whereby facilities emitting more than 100,000 tonnes of carbon dioxide per year can achieve compliance by:

(a) Improving operations;

(b) Purchasing carbon offset credits in Alberta;

(c) Using any current or prior emission performance credits; and

(d) Contributing to the Climate Change and Emissions Management Fund per tonne of carbon dioxide over the target.

The extension changes the cost of compliance for contributions to the Climate Change and Emissions Management Fund, by increasing contribution costs to $20/tonne in 2016, and $30/tonne in 2017. Contribution costs will remain at $15/tonne for 2015.

The extension also changes the target for emissions intensity as low as 85 percent of the baseline emissions intensity in 2016, and 80 percent of baseline emissions intensity in 2017. Targets for baseline emissions intensity remain unchanged for 2015.

The extended regulations are now set to expire on December 31, 2017.

Publication of CSA Z662-15 – Oil and Gas Pipeline Systems (June 18, 2015)
CSA Z662-15

The Canadian Standards Association recently published the latest version of CSA Z662-15, *Oil and Gas Pipeline Systems* ("CSA Z662").

CSA Z662 is incorporated by reference into a number of enactments and regulatory schemes throughout Canada. In Alberta, CSA Z662 is incorporated by reference pursuant to section 9 of the *Pipeline Regulation*, section 6 of the *Safety Codes Act*, and section 6 of the *Pressure Equipment Safety Regualtion.* Several AER directives also require compliance with the latest edition of CSA Z662.

The NEB in turn also released an information advisory notifying companies of the publication of CSA Z662. Pursuant to sections 1 and 4(1)(d) of the *National Energy Board Onshore Pipeline Regulations*, CSA Z662 is incorporated by reference into the regulations and came into force as of the date of its publication, June 15, 2015.

The NEB noted that due to the significant changes and additions to CSA Z662, it expects companies with current applications to provide information on how compliance with CSA Z662 will be achieved.

ALBERTA COURT OF APPEAL

Saskatchewan Power Corporation v Alberta (Utilities Commission), (2015 ABCA 183)
Appeal Denied - ATC

This decision arises from four separate appeals filed by Saskatchewan Power Corporation and its subsidiary Northpoint Energy Solutions ("Saskpower"), British Columbia Hydro and Power Authority and its subsidiary, Powerex Corp. ("BC Hydro"), ATCO Power Ltd. ("ATCO") and TransCanada Energy Ltd. ("TCE") regarding AUC Decision 2013-025: *Alberta Electric System Operator, Objections to ISO rule Section 203.6, Available Transfer Capability and Transfer Path Management* (February 1, 2013) ("*Decision 2013-025*").

Decision 2013-025 upheld *ISO rule Section 203.6: Available Transfer Capability and Transfer Path Management* (the "ATC Rule") proposed by the Alberta Electric System Operator ("AESO") governing the allocation of system available transfer capability ("ATC") over the interties that connect the Alberta electric system to neighbouring jurisdictions.

The respondents to the appeal, the AESO, Montana Alberta Tie Ltd., a wholly owned subsidiary of Enbridge Inc. ("MATL"), Morgan Stanley Capital Group Inc. ("MSCG") and NaturEner USA, LLC ("NaturEner") opposed the appeals, on the grounds that the findings in *Decision 2013-025* were reasonable.

The ATC Rule, as determined by the AESO, operates in the following manner:

(a) At T-2, or two hours before a given dispatch hour, pool participants submit to the AESO their interchange transactions over each of the interties;

(b) The AESO, at T-85, or 85 minutes before a given dispatch hour, determines if the combined individual transfer paths of the Alberta/BC intertie and MATL intertie will exceed ATC limits on those transfer paths. (Due to the configuration of the intertie owned by MATL, the Alberta/BC intertie and MATL share a capability limit for the purposes of ATC);

(c) The AESO, also at T-85, posts total import offers and export bids for individual paths and its ATC allocations for each transfer path;

(d) At no later than T-20, the AESO must receive pool participants' import and export transaction schedule submissions (known as "e-tags");

(e) The AESO then validates e-tags, and includes them in the interchange schedule as a dispatch in the energy market merit order. Following this step, the energy is physically dispatched onto the Alberta Interconnected Electric System for the dispatch hour.

The ATC Rule thus created a pro-rata methodology for allocating ATC in situations where there is more demand for ATC than there is capacity. This differed from the previous methodology in which the AESO would schedule dispatches over the Alberta/BC intertie, and the Saskatchewan/Alberta intertie, and would curtail transmission schedules on a last-in-first-out basis when transaction volumes are greater than ATC, according to the timing of e-tags. The AESO determined the continued operation of this last-in-first-out methodology could result in unfairness to market participants once the intertie owned by MATL became operational.

Decision 2013-025 dismissed objections from the appellants, who submitted that the ATC Rule was not in the public interest, did not support the fair efficient and openly competitive operation of the electricity market in Alberta, and that the ATC Rule was technically deficient.

Leave to appeal *Decision 2013-025* was granted on two questions:

(a) First, did the AUC err in law in its interpretation of section 29 of the *Electric Utilities Act* ("*EUA*") by finding that the AESO was required by statute to provide system access service to intertie operators; and

(b) Second, did the AUC err in law in its interpretation of section 16 and/or section 27 of the *Transmission Regulation* ("*T-Reg*")?

Section 29 of the *EUA* states "The Independent System Operator must provide system access service on the transmission system in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so."

Section 16 of the *T-Reg* provides that the AESO, in exercising its duties under the *EUA*, must prepare a plan to restore the operation of interties that existed on August 12, 2004 to their path rating, and to implement such a plan as soon as practicable. However, subsection 16(4) of the *T-Reg* provides that "This section shall not be interpreted as meaning that priority should be given to interties that existed on August 12, 2004 over interties existing after that date in respect of the allocation of available transfer capability."

Section 27(4) of the *T-Reg* applies to an intertie proposed to be constructed, and requires that the cost of planning, designing, constructing, operating and interconnecting an

intertie must be paid by the person proposing the intertie and other persons to the extent they directly benefit from the intertie.

The Alberta Court of Appeal ("ABCA") adopted a standard of review of reasonableness in reviewing *Decision 2013-025*.

Preliminary Matter

The ABCA addressed one preliminary matter seeking to strike parts of the facta of two appellants, ATCO and BC Hydro. The respondents requested striking portions of the appellants' facta on the basis that ATCO and BC Hydro's submissions strayed beyond the questions on which leave was granted, or that leave was denied on those questions.

ATCO and BC Hydro's facta disputed the finding that interties were part of the Alberta interconnected electric system, and that the AUC had improperly argued the AUC's interpretation of the term "reasonable opportunity" as it appears in section 28 of the *EUA* and section 15 of the *T-Reg*. ATCO and BC Hydro submitted that questions of statutory interpretation require consideration of the entire statutory scheme and context.

The ABCA determined that while statutes must be read in their entire context, it does not give a party free rein to reargue all statutory interpretations. A party must treat the remaining statutory interpretations by the tribunal as settled for the purposes of the appeal.

On those grounds, the Court granted the motion to strike the offending portions of the appellants' facta.

Analysis

The ABCA noted two findings of fact made by the AUC in *Decision 2013-025* that were critical to the decision on these appeals:

(a) Interties do not create ATC, but that ATC is a function of the underlying system and is realized by connecting those systems through an intertie; and

(b) ATC is a system resource and does not belong to any particular intertie.

On the issue of the AUC's interpretation of section 29 of the *EUA*, the ABCA noted the AUC's findings that "reasonable opportunity" in section 29 requires the AESO to treat each market participant, whether a generator or an intertie, equally. Access must be non-discriminatory, and that no advantage may be given to one participant over another. The Court also noted the AUC's finding that once a market participant has made an investment in infrastructure to connect to the Alberta electric system, it is clear that the market participant wishes to exchange energy.

The ABCA determined that the AUC's findings in this respect were well within their expertise, was not inconsistent with their prior decisions, and did not rely on any single modifying word of the enactment. Rather, it considered the overarching scheme and purpose of the *EUA* to ensure the fair, efficient and openly competitive operation of the electric market in Alberta.

The Court determined that the AUC's findings with respect to section 29 of the *EUA* in *Decision 2013-025* were not unreasonable.

With respect to section 16 of the *T-Reg*, the Court noted that the AUC interpreted subsection 16(4) of the *T-Reg* as preventing the balance of that section from being taken as the basis for giving priority ATC allocation to the interties existing on August 12, 2004. The AUC also determined that not granting priority ATC allocation to existing interties was appropriate in the context of the scheme of the *EUA*.

The appellants submitted that section 16 imposed an obligation on the AESO to restore the path ratings of each intertie, whereas the ATC Rule decreases the path ratings by allocating it amongst other interties such as the line owned by MATL. The appellants submitted that the ATC Rule thereby undermined the express purpose of section 16.

The ABCA rejected these arguments, finding that the obligation referred to a plan to restore the interties, and that there was no explicit timeframe for restoring the existing interties. Instead, the ABCA accepted the argument of the AESO, that section 16 cannot be used as a basis for providing a priority allocation of ATC, and that the scheme and context of the *EUA* requires the AESO to allocate ATC on a non-priority basis.

The ABCA held that, although some interpretations may give rise to a large number of possible, reasonable conclusions, the onus is ultimately on the appellants to show that the selected interpretation is one that the statutory language cannot bear. The Court determined that the AUC's interpretation of section 16 of the *EUA* in *Decision 2013-025* was therefore not unreasonable.

With respect to section 27 of the *T-Reg*, the Court noted the AUC's finding that there was no evidence persuading the AUC that the costs in section 27 of the *T-Reg* have not been paid by the operator of the MATL intertie. The AUC also found that ATC, as a system resource, did not belong to any one participant or intertie. As a result of this finding, the AUC also determined that intertie restoration costs were therefore appropriately characterized as system costs, and therefore outside the scope of the proceeding before the AUC.

The Court held that the factual determination that ATC was a system resource led the AUC to arrive at the not unreasonable conclusion, that ATC related costs were not costs under section 27 of the *T-Reg.*

Finally, the Court considered the broader public interest issues. The appellants argued that it cannot be in the interest of Alberta ratepayers for the AESO to allocate ATC to a privately owned and for-profit intertie in the manner that the ATC Rule does, and would deprive ratepayers of ATC paid for indirectly by the payment of their rates. Thus, since ATC is a public good, it should not be shared with or allocated to a private for-profit entity to the detriment of Alberta ratepayers.

The ABCA also rejected these arguments, noting that the public interest arguments strayed into the realm of cost considerations, and were not germane to the appeal itself.

In the result, the appeals from *Decision 2013-025* were dismissed, in effect, upholding the ATC Rule.

ALBERTA ENERGY REGULATOR

Release of Revised Joint Operating Procedures for First Nations Consultation on Energy Resource Activities (Bulletin 2015-20)
Bulletin – First Nations Consultation

The AER announced the release of a revised version of the Joint Operating Procedures for First Nations Consultation on Energy Resource Activities (the "Procedures"). The Procedures set out the administration and coordination of First Nations consultation between the AER and the Aboriginal Consultation Office ("ACO"). The Procedures were first announced on February 4, 2015 with the release of Bulletin 2015-04, but were later suspended pursuant to Bulletin 2015-10 on February 26, 2015 pending the implementation of a requirement to submit a First Nations consultation declaration form and associated requirements.

This Bulletin sets out those new requirements in section 4 of the Procedures, which take effect on July 1, 2015. As part of the requirement, the applicant for a project under a specified enactment (namely, the *Water Act*, the *Public Lands Act*, the *Environmental Protection and Enhancement Act*, and Part 8 of the *Mines and Minerals Act*) must identify whether First Nations consultation is required. If so, the applicant must provide the following information:

(a) A First Nations impacts and mitigation table, summarizing the First Nations consulted;

(b) Any potential adverse impacts on the existing rights of aboriginal peoples or their traditional uses identified during consultation; and

(c) Any mitigation proposed by the applicant during consultation.

Full details of the new requirements under the Procedures and specific submission format requirements can be found by clicking here.

ALBERTA UTILITIES COMMISSION

Alberta Electric System Operator 2014 ISO Tariff Compliance Filing Pursuant to Decision 2014-242 Module 1 (Decision 3473-D01-2015)
Compliance Filing – 2014 ISO Tariff

This decision arises from the AUC's Decision 2014-242 ("*Decision 2014-242*"), which directed the Alberta Electric System Operator ("AESO") to re-file its 2014 ISO Tariff application to reflect the findings and other directions provided in *Decision 2014-242*.

The compliance filing from the AESO was split into two modules by the AUC. Module 1 addressed directions 1 to 4 and 9 to 11 of *Decision 2014-242*, and Module 2 addresses directions 5 to 8 from *Decision 2014-242*. Module 2 has recently concluded, and a decision from the AUC for Module 2 is forthcoming.

As part of its re-filing, the AESO requested that the AUC:

(a) Confirm that the AESO has complied with Commission direction 1 to 4 and 9 to 11 from *Decision 2014-242*;

(b) Approve the 2014 rate calculation methodology provided as Appendix B of the application;

(c) Approve the 2014 ISO Tariff provided as Appendix E to the application, to be effective July 1, 2015 excluding subsection 3 of section 8 of the ISO Tariff which will remain as currently approved; and

(d) Approve Rider J on a final basis effective January 1, 2015.

The AUC held that the AESO adequately addressed and responded to the following directions from *Decision 2014-242*, and noted that they were not contested in the proceeding:

(a) Direction 1 – continue to exclude participant-owned projects from project database;

(b) Direction 3 – use 1.5 megawatt (MW) low end data point to calculate the point of delivery charge;

(c) Direction 4 would be addressed in a future AESO tariff or other application;

(d) Direction 9 – use project database as provided in information response ACCESS-AESO-001;

(e) Direction 10 would be addressed in a future AESO tariff or other application;

(f) Direction 11 – submit amended *pro forma* construction commitment agreement by December 31, 2014; and

(g) Rider J – Wind Forecasting Service Cost Recovery Rider, effective January 1, 2015 on a final basis.

With respect to Direction 2 in *Decision 2014-242*, the AUC directed the AESO to use the "full increased capacity made possible by an upgrade project", and that "if the AESO cannot reasonably determine this capacity level for any given project, then the project should be excluded from the database."

The AESO explained the point of delivery charges and maximum investment levels that would result from cost functions arising from different cost bases such as Greenfield projects and upgrade projects. The AESO submitted that it had fully complied with Direction 2, in proposing a declining scale for point of delivery charges and annual investment amounts. However, the AESO noted that there were unanticipated impacts, as were raised by interveners in the information request process.

As a result, the AESO submitted that it may be reasonable to delay the implementation of Direction 2 until the issue can be explored further in consultation with stakeholders. The Office of the Utilities Consumer Advocate ("UCA") and Devon Canada agreed with the AESO's proposed approach to resolving the new concerns.

The AUC agreed that the effects of Direction 2 were unanticipated, and held that the proposed plan of action by the AESO, to delay the implementation until the matter can be thoroughly explored, was reasonable, noting the agreement among the parties.

As a result, the AUC directed that, except for subsection 3 of Section 8 of the Terms and Conditions of Service, the 2014 ISO Tariff is approved effective July 1, 2015 including rates, riders, terms and conditions and appendices.

Initiating the ATCO Utilities information technology (IT) common matters proceeding to examine IT costs related to the master services agreements (MSAs) between the ATCO Utilities and Wipro Solutions Canada Limited (Wipro) (Bulletin 2015-11)
Bulletin – Common Proceeding - IT costs - MSAs

The AUC announced Proceeding 20514, a common matter to examine the costs for information technology ("IT") services common to ATCO Electric Ltd. and ATCO Pipelines Ltd. (the "ATCO Utilities"). The AUC advised that parties registered in Proceedings 3577 and 20272 will be registered

in Proceeding 20514. All other parties must file a statement of intention to participate by no later than 2:00 pm on July 6, 2015.

The ATCO Utilities had previously sourced their IT services from ATCO I-Tek, an unregulated affiliate, which was later sold to Wipro Solutions Canada Limited ("Wipro") in a share transaction. Subsequent to the sale, Wipro and the ATCO Utilities entered into a 10 year MSA.

The AUC announced that it required the proceeding to examine the future implications for regulated distribution utilities currently subject to performance-based regulation. Accordingly, the AUC directed the ATCO Utilities to re-file IT cost related information from Proceedings 3577 and 20272, being the general rate applications for both ATCO Gas and Pipelines Ltd., and ATCO Electric Ltd., respectively, by June 25, 2015. The AUC also directed the ATCO Utilities to re-file any proposed placeholders for IT costs in the general rate applications.

The AUC provided a preliminary list of issues for the common matter Proceeding 20514 which can be found here.

Interested parties may file written submissions in respect of any proposed modifications or additions to the issues list, as well as comments on process, by 4:00 pm on July 13, 2015.

TransAlta MidAmerican Partnership Sundance 7 Power Plant (Decision 3183-D01-2015)
Facility Application – Power Plant

TransAlta MidAmerican Partnership, a partnership between TransAlta Canadian Gas Development LP and MEHC Canada Genco Limited Partnership ("TAMA Power") applied for an 856-megawatt ("MW") combined cycle natural gas and steam generation facility, to be designated as Sundance 7 ("Sundance 7"). The Sundance 7 facilities are to be located in the Lake Wabamun area in Alberta on the west half of Section 10, Township 52, Range 4, west of the Fifth Meridian, and in close proximity to existing coal-fired power generation facilities.

While Sundance 7 will be located on a Greenfield site, it will be located adjacent to a number of existing power generation facilities and coal mines, including Sundance Generating Facilities 1 to 6, Keephills Generating Facility units 1 to 3, and other mining and energy projects.

Three intervener groups participated in the hearing, namely the Cymbaluk family, the Summer Village of Kapasiwin ("Kapasiwin"), the Gunn Métis Local 55 ("Gunn Métis") and the Paul First Nation ("Paul FN"). The intervener groups were concerned with the consultation, noise impacts, vegetation and wildlife impacts, impacts on waterbodies, air emissions, construction and traffic, safety and visual impacts, corporate structure of the parties proposing Sundance 7, and the cumulative impacts to aboriginal and treaty rights from increased traffic, noise and activity caused by Sundance 7.

Consultation

With respect to consultation matters, TAMA Power stated that it undertook personal consultations for stakeholders within 800 metres of the project site boundary, and notified residents within 2,000 metres of the project site boundary. TAMA Power also conducted First Nations engagement with the Paul FN, Gunn Métis, and the Enoch Cree nation. TAMA Power also submitted that it developed a public involvement program and provided project information packages to stakeholders, in addition to holding open houses and providing a website with project information.

The AUC determined that TAMA Power's efforts to identify aboriginal stakeholders was reasonable in the circumstances, and further made efforts to consider the specific concerns of the Gunn Métis. The AUC held that TAMA Power met the requirements of AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* by providing multiple avenues for landowners and other stakeholders to obtain information or contact TAMA Power.

Noise

TAMA Power filed a Noise Impact Assessments ("NIA") performed by Golder Associates Ltd. ("Golder"), with its application. TAMA Power submitted that the results of the initial NIA predicted that the project would comply with the permissible sound levels of 50 dBA L_{eq} daytime and 40 dBA L_{eq} nighttime, as set out by AUC Rule 012: *Noise Control*.

However, TAMA Power submitted that due to advances in project design, a second NIA was submitted to respond to intervener concerns. The updated NIA results were consistent with the previous NIA, predicting maximum daytime and nighttime noise limits of 46 dBA L_{eq} and 39 dBA L_{eq}, respectively.

TAMA Power noted that its NIA modelling included assessments of sound levels from existing facilities in the area. TAMA Power also noted that it modelled a noise barrier measuring 18.3 metres high and approximately 213 metres in length in its NIAs, to reduce the noise emitted towards the Cymbaluk family's residence.

The Cymbaluk family submitted that they were primarily concerned with high frequency and low frequency noise from the project, and stated that the existing noise impacts were unacceptable and non-compliant with current noise control requirements. An acoustics expert for the Cymbaluk family expressed concerns with the selection of ground absorption

factors, and the effects of wind and thermal inversion modelled in the NIAs. The Cymbaluks also questioned the effectiveness of the proposed noise barrier in the NIAs, noting that the "shadow zone" of the noise barrier would not mitigate noise under certain weather conditions.

The Cymbaluk family requested that the AUC direct that a safety margin be imposed on the acceptable noise limits for TAMA Power to account for any incaccuracies in the predicted versus actual noise impacts.

Kapasiwin expressed concerns that the project would add another noise source which could contribute to noise levels, and noted that the stack height of the proposed power plant would be 166 feet above ground level, providing limited options for sound attenuation. As such, Kapasiwin requested that the AUC direct that TAMA Power institute independent sound monitoring upon completion of the project.

The AUC determined that TAMA Power and Golder used a reasonable approach to modelling the noise impacts of the project. The AUC noted that not all models are inherently uncertain, and that noise control requirements do not require an applicant to take those uncertainties into account. However, the AUC held that even if the modelling is inaccurate, the applicant is required to operate its project in such a way that it will comply with permissible sound levels, which can be determined through post-construction sound level surveys.

The AUC also noted that the Cymbaluk family's outstanding noise complaints were the subject of another proceeding and that no determination was required in this decision.

Wildlife and Vegetation Impacts

TAMA Power retained Golder to prepare an environmental report and conduct fieldwork with respect to the potential impact of the project on vegetation and wildlife. TAMA Power submitted that the project site has historically been used for agricultural purposes, and also consists of remnant native woodlots, shrubs and wetlands.

TAMA Power submitted that the project was not likely to cause adverse environmental effects, and that an environmental assessment was not required under the *Canadian Environmental Assessment Act*, 2012. TAMA Power noted that there were no confirmed instances of rare plants during site surveys, and that the overall impact on vegetation from the project would be minor.

TAMA Power also noted a paucity of wildlife habitat on the project site, and submitted that the implementation of mitigation measures would have a negligible impact on wildlife and wildlife habitat.

Karen Kubiski submitted a report on behalf of the Gunn Métis on the effects of habitat loss and fragmentation. The Gunn Métis noted that Golder failed to assess the impact on native plant community types at the landscape level. The Gunn Métis noted specifically that sweetgrass habitat would be fragmented by the project, and would in turn make it more difficult for remaining patches of sweetgrass in the watershed area to reproduce and colonize. The Gunn Métis also criticized Golder's identification of vegetation, noting that it failed to identify tansy (*Tanacetum vulgare*), which the Gunn Métis noted was identifiable, even during winter months.

The Gunn Métis submitted that the Lake Wabamun watershed likely cannot sustain any further disturbance, while continuing to meet the ethnobotanical harvesting needs of the Gunn Métis.

The Gunn Métis therefore requested that the AUC approve the project on the follwoing conditions:

(a) That TAMA Power conduct a special-use vegetation survey of the Lake Wabamun watershed prior to construction, and the results and recommendations of that study be provided to the AUC six months prior to construction of the project;

(b) That TAMA Power consider establishing a native plant nursery to be planted in areas outside those disturbed by TransAlta; and

(c) That TAMA Power monitor sweetgrass and other threatened ethnobotanical species in the Lake Wabamun watershed.

The AUC determined that the nature and extent of the environmental reports commissioned by TAMA Power were adequate in the circumstances, and the AUC was not persuaded that a study of ethnobotanical plants was warranted, given the limited impacts on vegetation. The AUC also determined that, because the impacts of the project were limited to species available in the project area, there was insufficient evidence to conclude that the project would result in fragmentation of habitat for vegetation and wildlife. The AUC concluded that the project would have a minimal impact on wildlife, wildlife habitat and vegetation, given the footprint and current use of the project site. The AUC therefore rejected the requests for additional environmental work from the Gunn Métis.

Waterbodies

TAMA Power submitted that the project would use water from the existing Sundance industrial cooling pond, and would not draw from, nor discharge water into Lake Wabamun. Instead, TAMA Power would source and return its water to and from the industrial cooling pond from the

North Saskatchewan River, as allowed under existing approvals from Alberta Environment and Sustainable Resource Development ("ESRD"). TAMA Power noted that the project was designed so that the temperature of any water returned to the North Saskatchewan River would not be changed. Tama Power futher submitted that it expected minimal impacts on water quality.

TAMA Power also indicated that it would be compensating for any lost wetland habitat by a factor of 3 to 1 through Ducks Unlimited.

The Gunn Métis expressed concern about the lack of analysis for the potential for increased withdrawals and warm processed water flowing back into the North Saskatchewan River. The Gunn Métis also requested meaningful engagement on development of any wetlands as compensation. TAMA Power in turn committed to arranging meetings between the Gunn Métis and Ducks Unlimited for this purpose.

The AUC accepted TAMA Power's submissions that water withdrawals for the project would be limited to the water at the existing Sundance industrial cooling pond. The AUC found that the impacts on the North Saskatchewan River would be minimal, noting that the withdrawals would be within the limits of existing approvals from ESRD.

Air Emissions

TAMA Power submitted that the project would result in improved air quality because it would replace existing coal-fired generating power plants in the area, and that TAMA Power would implement a catalytic reduction system to mitigate air emissions impacts.

TAMA retained Golder to compare the baseline emissions in the area, the project-only emissions and the "application case" which included the emissions from the project in addition to the baseline emissions. Golder compared the predicted maximum ground level concentrations of nitrogen dioxide, carbon monoxide, fine particulate matter and ammonia to the Alberta Ambient Air Quality Objectives ("AAAQO"). Golder predicted that ground level concentrations of NO_2, fine particulate matter and ammonia would be below the AAAQO for the project's normal operations. Golder predicted no change to carbon monoxide concentrations or fine particulate matter concentrations, with the exception of:

(a) One carbon monoxide exceedance per year under the project's idling load operating conditions; and

(b) Two exceedances of fine particular matter due to forest fires and nearby mining operations.

TAMA Power submitted that despite these exceedance instances, the concentration levels for all inputs were well below the AAAQO requirements.

The AUC determined that, since the air modelling study was consistent with methodologies specified by ESRD, no additional modelling would be required if the project is approved. The AUC also held that any incremental difference in air quality due to the operation of the project would likely be minimal and temporary.

Health

The Gunn Métis had concerns with its members' proximity to the project, primarily due to exposure to fine particulate matter and nitrogen dioxide. The Gunn Métis retained Dr. Joseph Vipond ("Dr. Vipond") to provide evidence of the health impacts due to air emissions. Dr. Vipond presented evidence that there were no safe exposure limits to fine particulate matter and ozone, and that exposure to these substances was associated with small birth weight in babies, respiratory and cardiovascular diseases, strokes and autism.

Dr. Vipond found that the project would substantially increase fine particulate matter concentrations. Therefore, the Gunn Métis advocated for conditions imposing thresholds on ambient air quality near the project in order to protect the Gunn Métis members.

TAMA Power submitted that the project's emissions could only be hazardous to health if it has the capacity to cause health effects through significant exposure. TAMA Power submitted as an example, that the peak one-hour nitrogen dioxide concentration of 190 micrograms per cubic meter ($\mu g/m^3$) was short of the 1,100 $\mu g/m^3$ required to induce adverse effects. On this basis, TAMA Power did not expect the concentrations from air emissions from the project to result in adverse health impacts.

The AUC determined that while Dr. Vipond had expertise in human health, he did not appear to have specialized knowledge of the health effects of air emissions, and therefore weighed his evidence and findings as non expert evidence with respect to air modelling and interpretation of epidemiologic studies.

The AUC held that, while all the experts agreed that power plant air emissions are associated with adverse health effects, they disagreed on the level at which such effects may occur. The AUC agreed with the conclusions of TAMA Power in noting that the concentration of emissions was not likely to reach such a level that they would cause adverse health impacts, and further found that there was no evidence that the incremental increase in emissions would create any adverse health effects on members of the public.

Construction and Traffic

TAMA Power submitted that increased impacts due to construction activities would be temporary, and that it would introduce protocols to address any issues arising from construction, including bussing employees to and from work, and encouraging contractors to do the same. TAMA Power also committed to coordinating its shift changes in order to reduce or avoid any interference with peak traffic periods in the area.

The AUC agreed that impacts from construction would be temporary, and found that TAMA Power's proposed mitigation efforts, including bussing workers in, to be reasonable in alleviating any traffic issues in the area.

Safety

TAMA Power stated that the proposed power plant initially utilized anhydrous ammonia, which would be used in the selective catalytic reduction system to reduce emissions of nitrogen oxides, and is a requirement of ESRD. However, TAMA Power also noted that anhydrous ammonia is a corrosive chemical that can cause adverse health effects at low concentration levels. TAMA Power's initial risk modelling studies for anhydrous ammonia usage predicted that the potentially impacted area from a hazardous release at ground level would extend outside the project site, and resulted in a higher risk to the Cymbaluk family's residence. As a result of this finding, TAMA Power changed its project design to use aqueous ammonia, which it stated would reduce the potentially impacted area from a release to an area entirely within the project site.

TAMA Power stated that it hired Golder to conduct an Ammonia Tank Risk Modelling Study to examine the impacts of any accidental release.

Golder outlined a number of mitigation strategies designed to mitigate the chances of accidental releases. TAMA Power submitted that it would commit to implementing these mitigation strategies.

The Cymbaluk family retained Zelt Professional Services ("Zelt") to review the Golder report, which commented on numerous deficiencies in the Golder report, including the temperature at which modelling was conducted, and Golder modelling only one ammonia tank failure. The Cymbaluk family also expressed concerns that the emergency response plan had not been fully developed.

The AUC held that the evidence submitted by Zelt and by Golder both concluded that the change from anhydrous to aqueous ammonia greatly reduced the risk to nearby residents, and limited any potentially serious impacts to an area entirely within the project site boundary. The AUC directed TAMA Power to file a letter on the record of the proceeding when its emergency response plan had been finalized.

Visual Impacts

TAMA Power noted that the proposed power plant would be visible from areas around the project site, but submitted that it would not overwhelm the viewscape, as TAMA Power committed to plant additional trees to mitigate the impacts on the viewscape. TAMA Power conducted a Visible Plume Assessment for potential fogging and icing associated with air emissions for the project. TAMA Power submitted that the visible plume would likely dissipate rapidly, and have a negligible visual impact.

TAMA Power committed to:

(a) Follow the Illuminating Engineering Society of North America publication IES RP-33-14 and IES RP-20-14;

(b) Follow the International Dark-Sky Association's Fixtures Seal Approval for exterior lighting;

(c) Follow the International Illuminating Engineering Society of North America's, Lighting Handbook, Tenth Edition; and

(d) Where applicable follow the International Dark-Sky Association's Model Lighting Ordinance.

The AUC held that the visual impacts could be mitigated by planting additional trees, and through TAMA Power's commitments with respect to lighting.

Siting

TAMA Power submitted that its proposed site had been owned by TransAlta Corporation since 1975 and has been primarily used for agricultural purposes since that time, and would therefore be a "Greenfield site". TAMA Power noted that it selected the site, considering the existence of current operations owned by TransAlta Corporation, which would allow the power plant to use existing infrastructure and resources in place, while avoiding operational conflicts.

The Cymbaluk family submitted that their lands were adjacent to the project site, and therefore had strong reservations about the site selection.

The Gunn Métis indicated that the project may potentially impact archaeological, traditional and historical resources on the project site, as the project site was within the Gunn Métis' traditional lands.

The Paul FN stated that the project site was protected by Treaty 6, and that the traditional lands of the Paul FN included the project site. The Paul FN also expressed

concerns about the potential for gravesites within the project area, noting that their historical practice is to bury someone in an unmarked grave at the location where the person died.

The AUC held that, in considering whether a proposed site is suitable, it does not determine whether the site selected by the proponent is the best site or whether other sites were considered. The AUC's analysis is restricted to whether the proposed site is suitable, taking into account:

(a) Potential impacts on local residents and stakeholders;

(b) Proximity to existing transmission facilities;

(c) Availability of water and fuel supplies; and

(d) The nature of the land use in the area.

The AUC noted that the Cymbaluks were the only residents within 2,000 metres of the project site voicing concerns. The AUC also noted that there was no persuasive evidence regarding the potential gravesites that may be found on the project site, but noted that should any be found, TAMA Power committed to notify the Paul FN and Gunn Métis. The AUC held that the current framework for identifying gravesites is sufficient.

Accordingly, the AUC held that the location of the project site is suitable for the construction and operation of the project.

Corporate Structure

TAMA Power explained that TAMA Power itself was structured as follows:

(a) TransAlta Canadian Gas Development LP; and

(b) MEGC Canada Genco Limited Partnership,

as partners holding an interest in TAMA Power.

The TransAlta Canadian Gas Development LP, in turn, is owned 99.99 percent by TransAlta Corporation as a limited partner, and 0.01 percent by 1707226 Alberta Ltd. as a general partner (and wholly owned subsidiary of TransAlta Corporation). MEHC Canada Genco Limited Partnership is owned 99.99 by MidAmerican Canada Holdings Corporation as a limited partner, and 0.01 percent by MEHC Canada Genco CP Corporation as a general partner (and wholly owned by MidAmerican Canada Holdings Corporation). TAMA Power explained that the permits and licences, if granted, would be held by 1707226 Alberta Ltd.

The Cymbaluk family submitted that 1707226 Alberta Ltd. did not file the application, and argued that the application should be re-filed by the correct entity. The Cymbaluk family also submitted that 1707226 Alberta Ltd. was not qualified to hold an approval for a power plant under section 11 of the *Hydro and Electric Energy Act*.

The AUC indicated that the one requirement for eligibility to receive a permit or licence from the AUC is that the corporate entity be registered, incorporated or continued under the Alberta *Business Corporations Act*. The AUC held that 1707226 Alberta Ltd. met that requirement and is therefore eligible to receive a permit or licence. The AUC held that the applicant is entitled to arrange its corporate structure in a manner that most effectively advances its business interest, so long as it satisfies the requirements of the *Hydro and Electric Energy Act*.

Conclusion

Based on the findings made in this decision, the AUC determined that the proposed power plant was in the public interest, and therefore granted TAMA Power approval to construct Sundance 7.

EPCOR Energy Alberta GP Inc. Non-energy Regulated Rate Tariff Compliance Filing Application (Decision 3574-D01-2015)

Compliance Filing – Non-energy Regulated Rate Tariff

Pursuant to the AUC's directions made in Decision 2014-303 ("*Decision 2014-303*"), EPCOR Energy Alberta GP Inc. ("EEA") filed a compliance filing with respect to its 2014-2015 non-energy regulated rate tariffs ("2014-2015 RRT").

EEA requested that the AUC approve its:

(a) Refiled 2014-2015 RRT non-energy revenue requirement;

(b) Refiled rates and price schedules, effective July 1, 2015;

(c) True-up mechanisms for 2013, 2014 and 2015; and

(d) Terms and conditions.

The AUC noted that directions 1, 8, 9, 12, and 16 from *Decision 2014-303* related to future non-energy tariff applications, and therefore were not addressed. The AUC also found that EEA corrected a total of eight errors and omissions in its 2014-2015 RRT, the combined effect of which caused an increase in EEA's revenue requirement of $0.29 million in 2014, and $0.67 million in 2015, which were approved as filed.

The AUC directed EEA, as part of direction 2 in *Decision 2014-303*, to adjust its site count forecast to reflect the current eligibility criteria in the *Regulated Rate Option Regulation* of 250 MWh annual consumption. EEA submitted in its refiling, that it updated its site counts, and removed

attrition assumptions for site counts related to the changes in the regulated rate option eligibility. EEA submitted that the impact of this change increased its revenue requirement by $0.29 million in 2014 and $1.55 million in 2015.

However, after taking into account changes directed by the AUC in directions 3 and 4 related to forecast site count attrition rates and utility associates site counts, EEA submitted that the overall impact to its revenue requirement was an increase of $0.04 million for 2014 and $0.21 million for 2015.

The Office of the Utilities Consumer Advocate ("UCA") disagreed with EEA's refiling, noting that EEA had failed to use the most up to date site count information from its 2014 actual data, which it submitted was at variance with the EEA's forecasts.

The AUC determined that it traditionally requires a utility's revenue requirement schedules to be updated for any year-end actual rate base figures that become available prior to the close of the record, but does not generally apply those figures as a substitute for the applied-for forecasts. Accordingly, the AUC held that EEA's site count and attrition figures using November 2012 to October 2013 actual data was sufficient.

The AUC found that EEA's proposed forecasts were reasonable, and that EEA complied with directions 2, 3, and 4 from *Decision 2014-303*.

As part of Decision *2014-303*, the AUC directed EEA to provide an update of salary escalators for its unionized employees to account for the finalization and ratification of its agreements with the Civic Service Union 52. EEA submitted that, at the time of the refiling, it still did not have a ratified agreement, and requested that the AUC approve its initial request for salary escalators of 3.1 percent for 2014 and 3.4 percent for 2015.

The UCA submitted that the proposed salary escalators from EEA were outdated, and must be reviewed in light of the current state of Alberta's economy. The UCA submitted that recent quarterly forecasts provided a more reasonable forecast rate for 2015 of 0.7 percent. Accordingly, the UCA submitted that the salary escalators for 2014 and 2015 be adjusted downwards to 1.0 percent and 2.0 percent respectively. The Consumers' Coalition of Alberta ("CCA") argued that the AUC should conduct a further process after reply argument for parties to make submissions with respect to any further update on EEA's negotiated union agreements.

The AUC determined that it was not efficient to further delay the approval of non-energy rates by adding any further process, and held that it would make its decision based on the information available with respect to forecast salary escalators. The AUC rejected the alternative proposal of the UCA, noting that the downward adjustments were not supported by evidence. The AUC determined that EEA's requested salary escalators were reasonable, as they were consistent with previous applications, and therefore found that EEA had complied with direction 6 from *Decision 2014-303*.

Direction 10 in *Decision 2014-303* directed EEA to finalize its embedded corporate services costs for 2015 in its compliance filing. EEA submitted that its updated embedded corporate services costs resulted in a reduction of $0.18 million from EEA's initial filing, primarily as a result of recentralizing human resource services within its parent organization.

The CCA argued that EEA's embedded corporate services costs were over-forecasted for 2014 by approximately 7.9 percent compared to preliminary actual data. As a result, the CCA submitted that if the 2015 forecasts are based on the 2014 forecast data, that the 2015 forecasts should be reduced accordingly.

The AUC declined to make the adjustments requested by the CCA, as the adjustment would be for a single line item. The AUC considered that no adjustments were necessary to EEA's costs for embedded corporate services, and approved them as filed.

With respect to the remainder of the directions in *Decision 2014-303*, the filings were not contentious, and were approved as filed.

With respect to the true-up mechanisms and calculations requested by EEA, EEA proposed a true-up of the difference between interim and final charges over the period from July 1, 2015 to December 31, 2015. The AUC noted that EEA's submissions were not contested by any party, and were found to be reasonable upon review.

As a result, the AUC approved EEA's 2014-2015 RRT filings, true-up mechanisms, and terms and conditions, as filed.

ATCO Electric Ltd. 2015 Updated Interim Transmission Facility Owner Tariff (Decision 20338-D01-2015)
Updated Transmission Facility Owner Tariff – Interim Basis

ATCO Electric Ltd. ("ATCO") applied for its updated 2015 transmission facility owner ("TFO") tariff on an interim basis, effective June 1, 2015. ATCO initially applied a revenue requirement for its TFO tariff in the amount of $694.3 million for 2015, a figure which has subsequently been updated to $695.7 million. ATCO had also previously received approval for an interim 2015 TFO tariff revenue requirement of $579.0 million in Decision 2014-356. ATCO's updated interim TFO

tariff requested approval for recovery of the full updated $695.7 million in the current application.

ATCO submitted that its requested increase in revenue requirement was both probable and material, and the collection of revenue deficiencies would ensure that ATCO has adequate cash on hand to cover operational expense increases in the interim. The increase in revenue requirement was driven primarily by an increased depreciation expense from new capital additions going into service, and a change in net salvage parameters.

ATCO submitted that 100 percent of its 2015 revenue requirement was consistent with past AUC decisions, noting that the six year average of approved final revenue requirement amounts was 94 percent of the applied-for amounts.

The AUC held that the identified revenue shortfall of $116.7 million was a material amount, and that some relief was warranted for ATCO's interim 2015 TFO tariff. However, the AUC approved only 90% of ATCO's requested increase, in keeping with its past practice of only approving some portion of the requested interim rate. The AUC noted that controversial issues may arise in the course of ATCO's general tariff application. The AUC also held that an approval of 90 percent of the requested increase would balance the need to maintain rate stability, while avoiding imposing financial hardship on the applicant.

The AUC therefore approved ATCO's 2015 TFO tariff on an interim basis in the amount of $54,982,857 per month, effective June 1, 2015 until otherwise ordered by the AUC.

NATIONAL ENERGY BOARD

TransCanada PipeLines Limited Application for the King's North Connection Pipeline Project Decision and Order with Reasons to Follow (Letter Decision GHW-001-2014)
Pipeline Application

The NEB released its decision in respect of the TransCanada PipeLines ("TransCanada") application to construct and operate the King's North Connection Pipeline Project (the "Project") pursuant to section 58 of the *National Energy Board Act* ("*NEB Act*"), and request exemptions from sections 30(1)(a) and section 31 of the *NEB Act*. The NEB noted that its written reasons for the disposition would be released on or before August 6, 2015.

The NEB issued Order XG-T211-027-2015 and its associated conditions to approve the Project. The NEB also granted TransCanada's request for exemptions from section 30(1)(a) and 31 of the *NEB Act*. The NEB reminded TransCanada that despite the approval, it must still apply for leave to open the Project pursuant to section 47 of the *NEB Act* prior to placing any of the facilities in operation.

Pipeline Safety Act receives Royal Assent (June 18, 2015)
Pipeline Safety Act

The Minister of Natural Resources announced that Bill C-46, *An Act to amend the National Energy Board Act and the Canada Oil and Gas Operations Act*, entitled the *Pipeline Safety Act*, received Royal Assent on June 18, 2015.

The *Pipeline Safety Act*, as summarized by the Library of Parliament, enacts the following changes to the *National Energy Board Act* and the *Canada Oil and Gas Operations Act*:

(a) Reinforces the "polluter pays" principle;

(b) Confirms that the liability of companies that operate pipelines is unlimited if an unintended or uncontrolled release of oil, gas or any other commodity from a pipeline that they operate is the result of their fault or negligence;

(c) Establishes the limit of liability without proof of fault or negligence at no less than one billion dollars for companies that operate pipelines that have the capacity to transport at least 250,000 barrels of oil per day and at an amount prescribed by regulation for companies that operate any other pipelines;

(d) Requires that companies that operate pipelines maintain the financial resources necessary to pay the amount of the limit of liability that applies to them;

(e) Authorizes the NEB to order any company that operates a pipeline from which an unintended or uncontrolled release of oil, gas or any other commodity occurs to reimburse any government institution the costs it incurred in taking any action or measure in relation to that release;

(f) Requires that companies that operate pipelines remain responsible for their abandoned pipelines;

(g) Authorizes the NEB to order companies that operate pipelines to maintain funds to pay for the abandonment of their pipelines or for their abandoned pipelines;

(h) Allows the Governor in Council to authorize the NEB to take, in certain circumstances, any action or measure that the NEB considers necessary in relation to an unintended or uncontrolled release of oil, gas or any other commodity from a pipeline;

(i) Allows the Governor in Council to establish, in certain circumstances, a pipeline claims tribunal whose purpose is to examine and adjudicate the claims for compensation for compensable damage caused by an unintended or uncontrolled release of oil, gas or any other commodity from a pipeline;

(j) Authorizes, in certain circumstances, that funds may be paid out of the Consolidated Revenue Fund to pay the costs of taking the actions or measures that the NEB considers necessary in relation to an unintended or uncontrolled release of oil, gas or any other commodity from a pipeline, to pay the costs related to establishing a pipeline claims tribunal and to pay any amount of compensation that such a tribunal awards; and

(k) Authorizes the NEB to recover those funds from the company that operates the pipeline from which the release occurred and from companies that operate pipelines that transport a commodity of the same class as the one that was released.

The provisions of the *Pipeline Safety Act* will become effective on June 18, 2016, unless otherwise specified by an order of the Governor in Council.

Changes to Natural Gas Export Licence Term under Part VI of the National Energy Board Act – Consultation on Proposed Regulatory Amendments (June 29, 2015)
NEB Seeking Input – NEB Act Amendment

The NEB released a letter to interested parties, announcing that the *Economic Action Plan 2015 Act* received Royal Assent on June 23, 2015, which amended the *National Energy Board Act* to allow for the issuance of natural gas export licences for a term not exceeding 40 years.

As a result, the NEB announced that it was seeking input from interested parties on proposed amendments to the *National Energy Board Part VI (Oil and Gas Regulations)* for a new category of licences permitting the export of natural gas for a term not exceeding 40 years, including among other things:

(a) The filing requirements for the new licence category; and

(b) The terms and conditions the NEB may impose on the new licence category.

The NEB noted that the proposed amendments would not affect the regulation of pre-existing licences for the exportation of gas, propane, butane, ethane, and oil for terms not exceeding 25 years. Nor would there be any change to regulations governing orders for the exportation of gas, ethane or heavy crude oil for a term not exceeding 2 years, or for orders for the exportation of propane, butanes or oil other than heavy crude oil for a term not exceeding 1 year.

The proposed amendments can be found on the NEB's website, or by clicking here.

Quicksilver Resources Canada Inc. 29 July 2014 Application for a Licence to Export Liquefied Natural Gas National Energy Board Reasons for Decision (June 30, 2015 Letter Decision)
Export Licence - LNG

The NEB released its decision in respect of Quicksilver Resources Canada Inc.'s ("Quicksilver") application pursuant to section 117 of the *National Energy Board Act* for a licence to export liquefied natural gas ("LNG") for a period of 25 years, starting on the first date of export, at a point located on the north side of Campbell River, British Columbia at the outlet of the loading arm of the proposed LNG terminal.

Quicksilver applied for an export volume of 20 million tonnes, equivalent to 960 billion cubic feet, or 27 billion cubic metres annually. The maximum quantity of the licence would be for 25,875 Bcf, or 733 billion cubic metres.

Quicksilver submitted that the quantity of LNG proposed for export would not exceed the surplus remaining after allowance for foreseeable consumption in Canada. Quicksilver provided three reports forecasting Canadian consumption, long term gas supply and demand forecasts, and an outlook of Canadian LNG exports. Quicksilver's reports noted that Canada's gas markets were open and liquid, as well as supplied by a robust resource base. Quicksilver included nearly all of the NEB approved exports in its forecasts, up to 18 Bcf/d, despite Quicksilver's submission that the full approved LNG export volumes would be unlikely to materialize.

The NEB was satisfied that the resource base in Canada was sufficiently large to accommodate the reasonably foreseeable Canadian demand, as well as the LNG exports proposed by Quicksilver. The NEB also noted that the evidence provided by Quicksilver was generally consistent with the NEB's own market monitoring information, and further agreed with Quicksilver that not all LNG export licences issued by the NEB would be used to their full extent. On this basis, the NEB found that Quicksilver's projections were reasonable, and that there would be sufficient resources to meet Canadian demand plus the forecasted level of LNG exports.

Quicksilver requested an annual 15 percent tolerance to the amount of LNG exported in a given 12-month period, and also requested a sunset clause whereby the licence would expire ten years from the date of issuance if exports have not commenced on or before that date.

The NEB approved the requested 15 percent annual tolerance, noting that the maximum term quantity of the licence is inclusive of the 15 percent tolerance amount. The NEB also accepted the request for a sunset clause, noting it to be generally consistent with NEB practice.

The NEB approved the requested point of export of LNG at the outlet of the loading arm of a proposed LNG terminal located on the north side of Campbell River, British Columbia.

The NEB issued the licence to Quicksilver, subject to approval of the Governor in Council, having found that the quantity of gas to be exported by Quicksilver would be surplus to Canadian needs.