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DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA COURT OF APPEAL

Remington Development Corporation v ENMAX Power Corporation (2016 ABCA 6)
Leave to Appeal - Denied

Remington Development Corporation ("Remington") applied to the Alberta Court of Appeal ("ABCA") for leave to appeal AUC Decision 3368-D01-2015.

Remington's appeal concerns ENMAX Power Corporation's ("ENMAX") application to the AUC to relocate two transmission lines located in downtown Calgary. The transmission lines were constructed on lands originally owned by Canadian Pacific Railway ("CPR"), pursuant to a right-of-way agreement. Remington subsequently purchased the lands from CPR and was assigned the right-of-way agreement. In a previous decision, the Alberta Court of Queen's Bench determined that Remington had the right to terminate the right-of-way agreement with ENMAX, and directed ENMAX to apply to the AUC to relocate the transmission lines.

ENMAX applied to the AUC in August of 2014 to relocate the two lines across property owned by Alberta Infrastructure as its preferred location, along with five other viable route options. In Decision 3368-D01-2015, the AUC held that ENMAX's preferred option was not in the public interest on the basis that:

(a) It had no information before it regarding Remington's development plans for the land in question; and

(b) It had no information as to why the alternate routes (some of which crossed Remington's lands) were incompatible with Remington's plans.

The AUC further rejected the application on the basis that the relocation was not associated with meeting transmission system needs, nor was it the lowest cost option.

In its application for leave to appeal, Remington alleged that the AUC committed the following errors of jurisdiction and law:

(a) The AUC failed to consider or appreciate that ENMAX is trespassing on Remington's land and has no right of entry;

(b) The AUC erred in assuming that the Surface Rights Board would grant a right of entry and compensation, when the *Surface Rights Act* only applies prospectively and not retroactively; and

(c) The AUC exceeded its jurisdiction be effectively expropriating Remington's land without compensation.

The ABCA held that a high degree of deference to the AUC's findings was appropriate. The ABCA noted that the AUC has exclusive jurisdiction over the siting of transmission lines in Alberta, which is at the core of its mandate under the *Hydro and Electric Energy Act*.

The ABCA found that the issue in respect of expropriation was without merit, holding that the AUC acknowledged that if the transmission lines were to remain on Remington's lands, it would require an agreement as between the parties, or that the Surface Rights Board would have to determine compensation.

The ABCA also noted that Remington's failure to adduce any evidence before the AUC, or to participate in ENMAX's application to relocate the two lines across property owned by Alberta Infrastructure, along with five other route options, played a significant role in the AUC's decision to deny the ENMAX application. Therefore, in rejecting the ENMAX application, the ABCA held that the effect of the AUC decision was to confirm that the present siting of the transmission line was in the public interest. The ABCA noted that the next step in the proceedings would be for Remington and ENMAX to negotiate a satisfactory settlement. The ABCA noted that if such negotiations failed, the matter would proceed to the Surface Rights Board for a right of entry and compensation order.

Accordingly, the ABCA held that the AUC's decision fell within a range of possible, acceptable outcomes that are defensible in respect of the facts and the law. The ABCA therefore denied the application for leave to appeal.

ALBERTA ENERGY REGULATOR

Grand Rapids Pipeline GP Ltd. Compliance with Condition 11 of Decision 2014 ABAER 012 (2016 ABAER 001)
Condition Compliance – Pipeline Routing – Hearing Cancellation

In this decision, the AER declared that it was cancelling the public hearing on the compliance of Grand Rapids Pipeline GP Ltd. ("Grand Rapids") with condition 11 as set out in Decision 2014 ABAER 012 ("Condition 11").

Condition 11 directed Grand Rapids not to construct or carry out any incidental activities for two segments of its proposed pipeline until it satisfied the AER that its applied for route was superior. The section of the proposed pipeline to which Condition 11 applied was on lands owned by MEG Energy Corp. ("MEG"). MEG and Grand Rapids were the only parties to the hearing.

On April 16, 2015, Grand Rapids filed its compliance filing and requested that a hearing be scheduled. Grand Rapids submitted an analysis of its preferred route, as well as five alternative routes, including one route that avoided MEG's lands ("MEG Lands"). Grand Rapids submitted that based upon its analysis, its original applied-for route remained the superior route, and asked that the AER confirm that it could proceed to construction.

The AER set a hearing date which was re-scheduled several times and ultimately being set for December 8, 2015. On December 10, 2015, the parties informed the AER that they had reached a resolution for an agreed-upon route over the MEG Lands. MEG accordingly withdrew its objection, and indicated that it supported Grand Rapids in its submission of an amendment application for the applied-for route.

The AER relied on the following findings with respect to Condition 11:

(a) Grand Rapids submitted analyses of five alternative routes, including a number of routes that avoided the MEG Lands and the lands along the north side of the CN rail line and within Strathcona County's heavy industrial policy area;

(b) Grand Rapids included in its analyses a qualitative and quantitative comparison of the alternative routes against the applied-for route and information on stakeholder concerns;

(c) Grand Rapids provided additional information in response to information requests from the panel;

(d) Discussions between Grand Rapids and MEG resulted in the development of a proposed route amendment that addressed MEG's concerns;

(e) The proposed route amendment required consultation and negotiation with other directly affected parties. Grand Rapids received confirmation of non-objection from all parties directly affected by the proposed route amendment and submitted these to the AER; and

(f) Grand Rapids indicated that on this basis it would be able to file its proposed amendment application as a routine application.

The AER held that Grand Rapids' route amendment satisfied the intent of Condition 11 and directed Grand Rapids to file its proposed route amendment.

Manitok Energy Inc. Applications for a Pipeline and Multiwell Oil Satellite Entice Field (2016 ABAER 002)
Contested Application – Alternative Dispute Resolution

Manitok Energy Inc. ("Manitok") filed applications pursuant to section 7.001 of the *Oil and Gas Conservation Rules* for a pipeline and multiwell oil satellite. Several parties filed statements of concern with the AER to contest the applications. Manitok engaged in an alternative dispute resolution process led by an AER Commissioner, which resulted in agreement between the parties. On January 7, 2016 the statements of concern was withdrawn, and accordingly, the AER decided not to hold a public hearing. The AER approved both applications from Manitok.

ALBERTA UTILITIES COMMISSION

AltaGas Utilities Inc. Rule 028 Natural Gas Settlement System Code Exemption Extension (Decision 20885-D01-2016)
Exemption Extension – Rule 028 – Rule 002

AltaGas Utilities Inc. ("AltaGas") applied to the AUC for approval of an extension to its exemption from sections 2.11, 8.6.1.1 and 8.6.5.3 of Rule 028: *Natural Gas Settlement System Code Rules* ("*Rule 028*"), granted in Decision 3606-D01-2015, from January 1, 2016 to December 31, 2018.

AltaGas had originally applied for an exemption from *Rule 028* due to a discrepancy in the profiling classes it used for natural gas settlement as compared with the profiling classes mandated by *Rule 028*. As a result, AltaGas indicated that it would be unable to comply with certain sections of *Rule 028* related to the Select Retailer Notification ("SRN") and Wholesale Settlement Details ("WSD") profiling classes, and specific sections related to deeming of meter reads.

Subsequently, AltaGas applied to the AUC for an exemption related to its non-compliances for the period between January 26, 2014 and December 31, 2015. In that application, AltaGas indicated that it would become compliant with *Rule 028* in three to five years, following the implementation of its customer information system ("CIS"). AltaGas indicated that it would apply annually to extend the exemption until it achieved compliance with *Rule 028*.

AltaGas submitted that an extension of the exemptions was again warranted in order to avoid, what it characterized as, significant time and costs associated with implementing a temporary solution, and would minimize overall cost impacts to customers.

AltaGas also submitted that it was not aware of any retailer concerns, complaints or issues resulting from its non-compliance with *Rule 028* and its exemption extension request.

The AUC approved AltaGas' exemption request effective from January 1, 2016 through to December 31, 2018. The AUC noted that a single extension, rather than an annual extension would reduce regulatory burden and avoid additional temporary costs.

The AUC expected AltaGas to continue to have regular discussions with retailers in its service territory respecting the continued viability of a workaround to its *Rule 028* non-compliance issues that may arise. Therefore the AUC directed AltaGas to identify any new issues raised in discussions with retailers in its annual Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors* ("*Rule 002*") report. The AUC also directed AltaGas to confirm in its *Rule 002* annual report that it is still on schedule to be compliant with *Rule 028* by June 30, 2019.

Accordingly, the AUC made the following orders:

(a) The AUC granted to AltaGas a temporary exemption extension from the requirements of sections 2.11, Section 8.6.1.1(1)(b), and Section 8.6.3.2, Table 9, Sequence 8 of *Rule 028* until December 31, 2018; and

(b) The AUC directed AltaGas to monitor and report annually in its *Rule 002* annual report, the following specific items:

   (i) The number of pre-final error corrections for profiling classes received in regard to Section 5.2.1(2)(d) and if applicable, the reasons why the manual workaround did not eliminate the pre-final error corrections;

   (ii) Any new issues retailers have raised or potential customer dissatisfaction with respect to AltaGas' *Rule 028* non-compliances and any mitigation measures that AltaGas has taken; and

   (iii) A confirmation that it is still on schedule to be compliant by June 30, 2019, and to include specific details on the steps it has taken to become compliant.

Alberta Electric System Operator Needs Identification Document; ENMAX Power Corporation Facility Application – Foothills Area Transmission Development in the South of Calgary (Decision 3386-D01-2016)
NID – Facility Application

The Alberta Electric System Operator ("AESO") applied to the AUC pursuant to section 34 of the *Electric Utilities Act* for approval of a needs identification document ("NID") for a proposed 138-kilovolt (kV) transmission system reinforcement in south Calgary. The AESO directed ENMAX Power Corporation ("ENMAX") to submit a facility application to meet the need set out in the NID, pursuant to section 35(1) of the *Electric Utilities Act*. ENMAX filed a related facility application pursuant to section 14 and 15 of the *Hydro and Electric Energy Act* for a 138-kV transmission system reinforcement.

The AESO submitted that it requested the approval to resolve transmission system constraints and the long term reliable operation of the 138-kV system in south Calgary. The AESO requested approval of the need for the following major components:

(a) A new 138-kV transmission circuit between ENMAX substation No. 65 and ENMAX substation No. 41, with a connection to ENMAX substation No. 54;

(b) Reconfiguration of transmission lines 32.82L and 26.81L to form a direct connection between ENMAX substations No. 32 and No. 26; and

(c) Modifications, alterations, additions or removal of equipment required to undertake the work.

In its facility application, ENMAX requested approval of the following transmission facility additions and modifications:

(a) Construction of one new single circuit 138-kV transmission line between ENMAX substations No. 65 and No. 54, designated as 138-54.81L;

(b) Construction of one new single circuit 138-kV transmission line between ENMAX substations No. 54 and No. 41, designated as 138-41.84L;

(c) Connection of ENMAX substation No. 26 to ENMAX substation No. 32 by connecting existing transmission lines 138-26.81L and 138-32.82L at the intersection of Deerfoot Trail and Stoney Trail and designating this as 138-26.81L;

(d) Adding one circuit breaker to ENMAX substation No. 65; and

(e) Adding two circuit breakers to ENMAX substation No. 41,

(collectively, the "Project").

The AESO and ENMAX requested that the AUC consider the applications jointly, pursuant to section 15.4 of the *Hydro and Electric Energy Act*.

ENMAX submitted two proposed routes for the Project:

(a) A preferred route, which would begin at ENMAX substation No. 65, going west along Stoney Trail, then north on Macleod Trail, terminating at ENMAX substation No. 41; and

(b) An alternate route, which would begin at ENMAX substation No. 65, going south along 88 street SE, then west along 212 and 210 Avenue S.E, then north on Macleod Trail, terminating at ENMAX substation No. 41.

A large number of landowners and local stakeholders registered as participants in the proceeding. These parties raised the following issues:

(a) Impacts to property values;

(b) Electric and magnetic fields ("EMF") of the proposed transmission lines and their impacts on health; and

(c) Visual impacts.

<u>AESO NID Application</u>

With respect to the AESO NID application, the AESO stated that its Foothills Area Transmission Development Plan undertook two sensitivity studies, which confirmed for the AESO the continued need for the current transmission development as applied for. The AESO submitted that the sensitivity studies indicated that the 138-kV transmission system in the south Calgary area was prone to overloading under N-1 contingencies (i.e. when one transmission element is out of service).

The AESO submitted that it did not study alternatives to the proposed development, due to the impracticality of rebuilding the high capacity existing circuits in the south Calgary area, making the reinforcement to the 138-kV system the only reasonable alternative.

The AUC found that the AESO's NID was not technically deficient, and in the public interest.

<u>ENMAX Application</u>

Consultation

ENMAX submitted that it conducted a comprehensive consultation process that met the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* ("*Rule 007*"). ENMAX noted that it received statements of concern and opposition from landowners on both the preferred and alternate routes.

A large number of interveners opposed the routing of the Project, and expressed dissatisfaction with ENMAX's consultation process, submitting that the information presented by ENMAX was lacking, or that ENMAX's consultation efforts did not take intervener issues into account.

While the AUC noted the concerns expressed by interveners, the AUC assessed ENMAX's consultation in light of the nature and scope of the entire Project. The AUC found that ENMAX provided sufficient information to potentially affected parties and provided opportunities for those parties to express their concerns. As a result, the AUC held that ENMAX's consultation program complied with *Rule 007*.

Electrical Considerations

Several parties expressed concerns about elevated risks of exposure to EMF, and impacts of the Project on health, noise, interference with computer equipment and induced current and voltage. ENMAX submitted that EMF are found everywhere that electricity is used, and it would continue to monitor EMF-related development. However, ENMAX submitted that scientific research to date has not established any adverse health effects from exposure to EMF from transmission lines at levels normally associated with those found in homes, schools or offices.

ENMAX submitted that the strength of the magnetic field decreases quickly with distance, increases with increased current, and may be impacted by the arrangement of conductors. ENMAX noted that where possible, it would arrange its conductors to reduce EMF at the nearest residences, and would provide in-home EMF measurements pre and post-construction on the request of any resident.

ENMAX submitted that its modelled EMF values for the preferred and alternate routes would be approximately 86 milligauss (mG) at the centreline, 5 mG at 30 metres from the centreline, 2 mG at 50 metres from the centreline, and less than 1 mG at distances greater than 80 metres from the centreline. ENMAX submitted that the 80 metre values were in the range typically found within Calgary homes and emitted by household fixtures. ENMAX further submitted that these values were well below the 2,000 mG exposure limit set out in the International Commission on Non-Ionizing Radiation Protection guidelines.

Interveners also expressed concerns with corona noise, which is a humming or buzzing noise from the transmission line due to electrical discharge and ionization of air around the surface of an alternating current transmission line conductor. ENMAX submitted that in order to mitigate noise, it would install corona shields on all insulators and would use large diameter conductors to ensure that there are no sharp edges on the conductor. ENMAX also submitted that it would undertake an annual maintenance program to detect and repair corona issues.

The AUC held that ENMAX's EMF modelling was credible, and accepted that the EMF levels decreased rapidly with an increase in distance from the line. As a result, the AUC held that the expected EMF values from the transmission line would be well below the International Commission on Non-Ionizing Radiation Protection guidelines. The AUC accordingly found no evidence to suggest that there would be adverse health impacts from EMF in relation to the Project.

The AUC also held that ENMAX's mitigation measures for corona noise, would assist in reducing the noise from the project, and therefore determined that the preferred and alternate routes for the Project were acceptable regarding electrical considerations.

Property Value and Visual Impacts

ENMAX submitted a land impacts assessment report from Golder Associates ("Golder") assessing four route options based on the criteria in *Rule 007*. Golder noted that the impacts were site specific and subjective, making estimates difficult.

Golder also noted that existing transmission and distribution lines were located adjacent to existing residential properties in the assessment area. Overall, Golder concluded that impacts to property values were more likely to occur along transmission line routes that are in proximity to a greater number of residential properties. As a result, Golder stated that the preferred and alternate routes have the lowest number of residential properties, and hence the lowest impact on residential property values.

With respect to visual impacts, Golder noted that the transmission structures are expected to be visible from residences, roads and recreational installations in the assessment area. However, Golder noted that the preferred route would have the lowest visual impact as it was the shortest, and made the most use of existing rights-of-way to reduce residential, environmental and visual impacts.

ENMAX also proposed to construct the line with steel monopole towers, which would reduce the visual impacts and number of towers relative to lattice towers or wood towers.

Interveners submitted a report from Gettal Appraisals Ltd. (the "Gettel Report") to conduct a financial impact assessment on the impact of the Project on residential property values. The report from Gettel limited its consideration to homes within 150 meters of the Project with a direct sightline on the Project, and conducted appraisals on three homes in the area.

The Gettel Report used three case studies to assess the impacts:

(a) Vacant residential lots adjoining a 138-kV transmission line west of Edmonton;

(b) Properties in Sturgeon County adjacent to the Heartland Transmission project; and

(c) Properties adjacent to a 138-kV to 240-kV transmission line upgrade near Tsawwassen in British Columbia.

The Gettel Report concluded that the typical range of anticipated value lost was correlated with the proximity of the property to the Project as follows:

(a) 0-50 metres with a clear sightline: 15 percent loss;

(b) 50-100 metres with a clear sightline: 10 percent loss; and

(c) 100-150 metres with a clear sightline: 5 percent loss.

The Gettel report estimated a cumulative economic loss of \$3,783,350 as a result of the Project on residential property values.

Interveners were also supported by two local developers, who submitted evidence that they had discounted lots in close proximity to the Project by between 5 and 10 percent, and that generally, the presence of major regional infrastructure has a negative effect on property prices.

The AUC held that, while it agreed with the approach taken by the Gettel Report, it did not accept the conclusion of a 5 to 15 percent value diminution, since the Gettel report relied heavily on its case study in British Columbia, which the AUC held was not comparable in respect of the properties, or the proposed Project.

With respect to visual impacts, the AUC held that the proposed route would be the furthest away from residences, and the location of the Project along existing rights-of-way would result in much lower visual impacts than other proposed routes.

Environmental Impacts

ENMAX submitted that no adverse impacts on land use were anticipated, given that the Project would be located on existing rights-of-way in a developed, urban environment. However, ENMAX committed to conducting additional field surveys prior to the start of construction in order to allow for site-specific measures to be developed as required.

ENMAX also noted that the alternate route would have a much higher potential for adverse environmental impacts, since it did not traverse existing rights-of-way, and instead traversed environmentally significant areas.

The AUC held that the proposed Project would be located in an urban, highly disturbed area, most of which would be on an existing right-of-way. The AUC held that both the preferred route and the alternate route were viable from an environmental impact perspective. However, because of the potential impacts to wetlands, the AUC held that a review of the environmental impacts favoured the preferred route.

<u>Conclusion</u>

In keeping with the findings and determinations above, the AUC held that the preferred route for the Project would have less of an overall impact than the alternate route and that its approval was therefore in the public interest, in accordance with Section 17 of the *Alberta Utilities Commission Act*.

Accordingly, the AUC approved the AESO's NID application as filed, and approved ENMAX's Project application along the preferred route.

Alberta Electric System Operator – 2013 and 2014 Deferral Account Reconciliation (Decision 20866-D01-2016)
Deferral Account Reconciliation

The Alberta Electric System Operator ("AESO") applied to the AUC for approval of the AESO's deferral account balances for 2013 and 2014, and for changes to deferral account balances for the years 2007 through 2012 previously considered by the AUC.

The AESO requested approval to settle the current deferral account amounts with market participants on an interim basis, subject to adjustment in a final decision, as follows:

(a) A shortfall of \$40.2 million of costs for 2014 (first reconciliation);

(b) A surplus of \$18.0 million of costs for 2013 (first reconciliation);

(c) A surplus of \$0.5 million of costs for 2012 (second reconciliation);

(d) A surplus of \$9.1 million of costs for 2011 (third reconciliation);

(e) A surplus of \$12.4 million of costs for 2010 (third reconciliation);

(f) A shortfall of \$0.4 million of costs for 2009 (fourth reconciliation);

(g) A shortfall of \$0.2 million of costs for 2008 (fifth reconciliation); and

(h) A shortfall of $0.1 million of costs for 2007 (sixth reconciliation).

The AESO requested the collection and refunds of the above amounts through the use of a one-time collection/refund option, and proposed to make settlement payments and collections in December 2015.

The AESO submitted that its deferral account reconciliation was prepared in the same manner as its previous deferral account reconciliation applications, and were prepared on a retrospective, monthly, and production month basis.

No party filed argument respecting the AESO's methodology in preparing the deferral account reconciliation. The AUC approved the methodology as filed, noting that it was consistent with past decisions on AESO deferral account reconciliations. The AUC also approved the AESO's proposal to settle the outstanding amounts through a one-time collection/refund mechanism, with a three-month option for market participants to pay if the one-time payment represented a significant financial burden.

ATCO Electric Ltd. ("ATCO") and EPCOR Distribution & Transmission Inc. ("EDTI") both opposed the AESO's timing for the interim settlement. ATCO and EDTI submitted that a settlement in December 2015 would not allow sufficient time to settle the interim amounts with customers in 2015, which would in turn, force each to report on the interim settlement in their 2015 fiscal year, but actually settle the accounts in their 2016 fiscal year. Accordingly, ATCO and EDTI requested that the AESO make its interim settlements in January 2016 to mitigate financial reporting effects.

In a separate ruling, the AUC held that it would not authorize the AESO's proposed settlement in late 2015 on an interim basis, based on submissions from ATCO and EDTI that accounting standards would require them to report these amounts in 2015, without being able to reflect the corresponding amounts to its customers for the same period.

The AESO submitted that the applied for deferral account reconciliations related to ancillary services costs, losses costs, and the AESO's own administrative costs, which are approved by the AESO board, pursuant to section 8 of the *Electric Utilities Act*. The AESO submitted that pursuant to sections 46(1) and 48(1) of the *Transmission Regulation*, once these costs are approved by the AESO board, they must be considered 'prudent' by the AUC unless an interested person satisfies the AUC otherwise.

No party filed argument respecting the prudence or amount of the AESO's costs in its deferral account reconciliation.

In noting that no party submitted evidence regarding the prudence of the AESO's costs approved by the AESO board, the AUC approved the AESO's own administrative costs, ancillary services costs, and losses costs as filed.

Accordingly, the AUC also approved the settlement of the deferral account balances with a net deferral account shortfall from 2007-2014 in the amount of a $0.8 million.

Alberta Direct Connect Consumer Association ("ADC") requested that the AUC make the following orders with respect to the AESO's deferral account reconciliation application:

(a) Mandate a deadline for future deferral account reconciliations within three to four months after the calendar year to avoid delays, as has happened in this application for 2013 costs;

(b) Direct the AESO to pay interest on refunded amounts using the 2013 generic cost of capital as a benchmark; and

(c) Create a streamlined procedure for interim demand transmission service tariff updates to be filed and implemented whenever the amount for Rider C in the ISO Tariff is greater than $2/megawatt-hour.

The AESO submitted that its decision to delay the 2013 deferral account balances was primarily due to the directionally opposite balances for 2013 and 2014, and that combining the two into a single application would avoid refunding a surplus in 2013 and collecting a separate shortfall in 2014. The AESO also submitted that accumulated interest on market participant deferral account balances was dealt with in Decision 2009-010, and that the redistribution of interest on outstanding amounts among market participants was inappropriate.

The AUC held that any deadlines for future deferral accounts reconciliation applications, or proposed changes to the Rider C amounts in the ISO Tariff, should be addressed as part of the consultation between the AESO and market participants regarding annual tariff updates, and declined to issue a ruling on this matter.

With respect to the accumulation of late interest on balances to market participants, the AUC held that the AESO's practice of netting shortfalls and surpluses in multiple years to be a reasonable practice. Accordingly, the AUC declined to reconsider its previous determination in Decision 2009-010 disallowing accumulated interest on deferral account balances.

In accordance with the above determinations, the AUC approved the AESO's deferral account reconciliation application as filed.

ATCO Gas and Pipelines Ltd. (South) Southwest Edmonton Connector Pipeline (Decision 201512-D01-2016)

Pipeline Application

ATCO Gas and Pipelines (South) ("ATCO") applied for a high-pressure pipeline known as the Southwest Edmonton Connector (the "SWEC") pursuant to section 11 of the *Pipeline Act* and section 4.1 of the *Gas Utility Act*. The SWEC would be 21 kilometres in length, 508 millimetres in outside diameter, and run from Stoney Plain Road to 127 Street S.W within the transportation and utility corridor ("TUC) along the Whitemud Drive road allowance in southwest Edmonton. The SWEC would also consist of the following components:

(a) A 130 metre lateral, with an outside diameter of 323.9 millimetres, to connect the main SWEC pipeline to the proposed Terwillegar Gate station;

(b) A 190 metre lateral, with an outside diameter of 168.3 millimetres, to connect the main SWEC pipeline to the existing Cameron Heights Gate Station;

(c) A 190 metre lateral, with an outside diameter of 168.3 millimetres, to connect the main SWEC pipeline to the proposed Whitemud Gate Station; and

(d) A 1.76 kilometre lateral, with an outside diameter of 323.9 millimetres, to connect the main SWEC pipeline to the existing Swan Hills pipeline (Licence 3861).

ATCO submitted that the SWEC would be wholly contained within the TUC, with the exception of a 0.76 kilometre portion, which connects to the Swan Hills pipeline. ATCO submitted that the SWEC forms part of ATCO's program known as the Urban Pipeline Replacement Project ("UPR"), which was approved in Decision 2014-010 where the AUC directed ATCO to file applications for individual pipeline projects within the UPR.

The AUC noted that the Edmonton TUC is located within the Edmonton Restricted Development Area, and the Sherwood Park West Restricted Development Area, which confine activities that are potentially harmful to the environment within the restricted development areas, separating them from operations or activities on adjacent lands.

The AUC also noted that pursuant to section 4(2) of the *Edmonton Restricted Development Area Regulations*, the AUC could not issue a permit or licence permitting construction within the restricted area without the written consent of the Minister of Infrastructure. Therefore, the AUC held that it had the jurisdiction to approve the SWEC application, on the condition that ATCO provide the AUC with the written consent of the Minister of Infrastructure.

The Chinatown Multi-level Care Foundation (the "Foundation"), a registered non-profit organization, objected to ATCO's application on the ground of risk and safety. The Foundation submitted that it owned land adjacent to the TUC, and it was planning to begin construction of a long-term care facility for seniors at that location beginning in July 2016, with completion slated for May 2018. The Foundation submitted that the City of Edmonton had rezoned the Foundation's land on January 30, 2012 to allow for the development of its long-term care facility, and the development permit was granted on September 11, 2014.

ATCO stated that it consulted with Alberta Infrastructure in respect of the location of the SWEC within the TUC. Alberta Infrastructure directed ATCO to use the outside 10 metres of the pipeline component of the TUC as the right-of-way, noting that development in this manner, would avoid the need for future pipeline construction to occur across or over existing pipelines.

<u>Pipeline Design and Integrity Management</u>

ATCO submitted that it designed the SWEC as a Class 4 pipeline, pursuant to the Canadian Standards Association Z662-15 – Oil and Gas Pipeline Systems ("CSA Z662"). ATCO further noted that the SWEC exceeded the required standard, as the dwelling density in the surrounding area would qualify the SWEC as a Class 3 pipeline. ATCO submitted that if a pipeline is designed to be a Class 4 pipeline, no setback requirement is imposed for the pipeline in question beyond the right-of-way.

ATCO also proposed to install remote operated valves in lieu of automated valves, so that ATCO could isolate sections of the pipeline for maintenance while maintaining flows to each gate station using different valve configurations. ATCO stated that this operational capability necessitated non-automated valves, which it submitted could be subject to malfunction. ATCO proposed to install valves approximately 5.1 kilometres apart, although it noted that Class 4 pipelines only require valves to be installed every 8 kilometres.

ATCO proposed an integrity management program for the SWEC, including the use of in-line inspections using a combination of calipers, magnetic flux leakage tools, and internal mapping tools. ATCO submitted that it would gather baseline information in respect of the condition of the SWEC prior to commissioning, which would feed into its risk assessment and work prioritization efforts. ATCO submitted that it would conduct in-line inspections at a frequency of 5 to 10 years, and flame ionization surveys by walking the pipeline twice a year.

For emergency response matters, ATCO submitted that it would continuously monitor pressure data on the SWEC on its Supervisory Control and Data Acquisition ("SCADA") system, which would be capable of detecting quick pressure drops caused by pipeline ruptures. ATCO also submitted that due to the ring design of the UPR, ATCO is able to shut down portions of the pipeline, so as to not impact the remainder of the city of Edmonton. In response to information requests from the Foundation, ATCO confirmed that it regularly conducted corporate emergency response exercises, including 18 exercises in 2014. ATCO declined to comment further, as its safety procedures and protocols were confidential, and might disclose security risks on its pipelines. However, ATCO indicated that it was willing to discuss its procedures with the Foundation, and was willing to conduct joint emergency response exercises with the Foundation.

<u>Risk Assessments</u>

The AUC considered a primary issue in the proceeding to be whether the risk associated with the proposed SWEC being in close proximity to the Foundation's proposed care centre was acceptable. ATCO and the Foundation each provided expert reports examining the risk assessments for the SWEC.

Both experts from ATCO and the Foundation agreed that the two most likely hazards to the Foundation's proposed care centre was due to either a fireball or a jet fire cause by a rupture to the SWEC. Both experts noted that following a rupture, primary ignition would first create a fireball, which would last between 8 and 30 seconds, followed by a jet fire, which would degrade as the pipeline slowly depressurized.

ATCO's expert submitted that, given the design, location, and the product that the SWEC would carry, it eliminated internal corrosion, stress corrosion cracking and geotechnical and hydro-technical forces as potential failure mechanisms. ATCO's expert filtered data from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") in the United States to survey failure rates, and the frequency of material and construction defects, and for incorrect operations. ATCO's expert noted that a significant factor in rupture frequency from third party damage was the restrictions on ground disturbance activities in the TUC, making such disturbances unlikely.

ATCO's expert submitted that the impact severity of accidents are a function of the distance from the risk source, with the risk of a fatality decreasing with distance from the source. ATCO's expert calculated the maximum individual risk for the segment adjacent to the Foundation lands as approximately 0.27×10^{-6} per year (i.e. 0.27 in a million chance). On this basis, ATCO's expert submitted that the individual risk was acceptable for all land uses, based on the Major Industrial Accidents Council of Canada guidelines, which require a 1×10^{-6} per year risk (i.e. 1 in a million chance). ATCO's expert also took the view that ATCO's decision not to use automatic valves was appropriate from a risk perspective, since automatic valves have not shown to contribute to safety in the way they were originally perceived to do.

The AUC held that the risk associated with the SWEC at its proposed location was acceptable, noting the design standards of the SWEC as a Class 4 pipeline under CSA Z662, and ATCO's commitment to integrity management and emergency response measures.

The AUC found the evidence respecting risk assessment submitted by both parties to be helpful, and provided a useful frame of reference for determining the possible envelope of risk in operating the SWEC. The AUC also noted that some of the expert evidence for risk assessments did not take into account integrity management activities, which it held would further reduce the risks of operating the SWEC in close proximity to the Foundation lands.

<u>Conditions Requested by the Foundation</u>

The Foundation requested that ATCO provide it and the AUC with other routing alignments that would minimize impacts on the Foundation's lands. However, as the AUC already held that the risk associated with the SWEC at its proposed location was acceptable, the AUC did not consider it necessary to make any findings on this requested condition.

The Foundation requested that ATCO consider installing barriers, blast walls or other features to protect the Foundation's care facility residents in the event of a leak, explosion or fire on the SWEC. The AUC also rejected this proposed condition, noting that the design features of the SWEC as a Class 4 pipeline under CSA Z662, in addition to ATCO's integrity management program, would provide the necessary features to protect the care facility residents.

The Foundation also requested that ATCO commit to ongoing engagement and communication with the Foundation regarding safety protocols, emergency response plans and emergency exercises. ATCO submitted its willingness to work with the Foundation on conducting emergency response exercises. As a result, the AUC directed ATCO to conduct table-top emergency exercises with the Foundation within 12 months of the SWEC becoming operational.

Conclusion

The AUC held that the SWEC was in the public interest, and approved the application pursuant to section 11 of the *Pipeline* Act and section 4.1 of the *Gas Utilities Act*, subject to two conditions:

(a) ATCO conduct table-top emergency exercises with the Foundation within 12 months of the SWEC becoming operational; and

(b) ATCO obtain written consent from the Minister of Infrastructure for the construction and operation of the SWEC within the Edmonton TUC.

AltaLink Management Ltd. 2010-2011 Direct Assign Capital Deferral Account Audit of Southwest Transmission Project (Decision 2044-D01-2016)
Direct Assign Capital Deferral Account Audit

This proceeding and decision arose out of AltaLink Managment Ltd.'s ("AltaLink") 2010-2011 direct assign capital deferral account ("DACDA") application considered as part of Decision 2013-407. In that decision, the AUC ordered an independent audit for AltaLink's costs associated with the Southwest 240kV Project (the "SW Project"). The AUC held that the evidence on the record was not sufficiently detailed for the AUC to make a final prudence assessment of the SW Project, approving instead a placeholder for the SW Project. The AUC retained Midgard Consulting Inc. ("Midgard") to perform an independent audit, which was filed on the record of this proceeding (the "Midgard Report").

The SW Project is a 240-kV double circuit transmission line and transmission system reinforcement project extending from Lethbridge, Alberta to Pincher Creek, Alberta. In Decision 2013-407, the AUC noted that the initial estimate in AltaLink's proposal to provide services in 2005 ("2005 PPS") for the SW Project was approximately \$78 million, while the final cost of the SW Project, filed as part of the DACDA application, was approximately \$224 million.

Procedural Background

Prior to determining the substantive issue of the prudence of AltaLink's SW Project costs, the AUC considered the following procedural issues in the proceeding:

(a) Legislative Scheme;

(b) Participation of Piikani Resource Development Ltd. ("PRDL");

(c) Relationship between the Midgard Report and the AUC's prudence assessment;

(d) Impartiality of Midgard;

(e) Scope of the Midgard Report; and

(f) Information available for the audit.

As part of the procedural background to the proceeding, the AUC canvassed the legislative framework applicable to project costs for transmission facility owners ("TFOs"). The AUC also reviewed ISO Rule 9.1 – Compliance Monitoring, which includes a number of project reporting and project procurement practices. As part of that review, the AUC stated that the Alberta Electric System Operator ("AESO"), while it has a significant impact on TFOs, does not have a mandate to assess prudence of project costs. The AUC determined that this mandate falls squarely within the AUC's own authority to set just and reasonable rates. As a practical matter however, the AUC noted that the AESO's actions frequently have a significant bearing upon the AUC's assessment of the prudence of project costs.

With respect to the participation of PRDL, the AUC noted that PRDL (a wholly owned corporation of the Piikani Nation) did not participate in the initial proceeding leading to Decision 2013-407. However, PRDL registered to participate in this proceeding, noting that PRDL holds the right to purchase an equity stake in the portion of the SW Project that traverses the Piikani reserve.

The Consumers' Coalition of Alberta ("CCA"), while it did not oppose PRDL's participation, urged the AUC to disregard, or give little weight to the submissions of PRDL, given their alignment with AltaLink's interests in requesting a finding that the SW Project costs were prudently incurred. The AUC rejected the CCA's submission that PRDL's submissions be given little weight on the basis that the AUC assigns weight to evidence, not argument.

With respect to the relationship between the Midgard Report and the AUC's mandate to assess prudence, PRDL submitted that section 122(1) of the *Electric Utilities Act* required the AUC to allow a utility a reasonable opportunity to recover prudently incurred capital costs. PRDL further submitted that recent jurisprudence from the Supreme Court of Canada did not require the application of a specific methodology to assess prudence, but an appropriate test for the prudence review would be the no-hindsight test.

The AUC held that Midgard's practice of not imposing a "20/20 hindsight" standard was compliant with the AUC's direction to audit the SW Project in Decision 2013-407.

The AUC emphasized that Midgard's practice was distinct from the AUC's own application of a prudence test, as Midgard was not retained to assess prudence.

The AUC also held that the recent decisions from the Supreme Court of Canada affirmed that the AUC may select the test it considers applicable in the circumstances, and accordingly held that Decision 2001-110 would continue to apply for prudence assessments. Decisions on prudence must reflect the information a TFO knew or ought to have known at the time.

With respect to Midgard's impartiality, the AUC held that the testimony of the witness from Midgard established that Midgard maintained its independence throughout the development of the Midgard Report.

The AUC held with respect to the audit scope, that it clearly set out the scope in Decision 2013-407, holding that "the choice of reverting to an alternate route will not be included in the scope of the audit."

The AUC determined that Midgard considering the cost of another route did not mean that Midgard proposed an actual alternate route, but rather attempted to develop a proxy to benchmark AltaLink's costs. However, the AUC rejected any comparison to other transmission lines, holding that it could not rely on the proxy developed by Midgard, since the proxy:

(a) Was based on a 2007 forecast of project costs, which had a wide range of accuracy;

(b) Was a longer route, and would have required additional labour, material and was subject to the same escalation rates; and

(c) Was a different route which would have been the subject of landowner opposition, and potential delays occasioned by multiple appeals to the Surface Rights Board.

With respect to the CCA having argued that AltaLink had failed to provide adequate data to Midgard, the AUC noted that Midgard did not raise any concerns with the content of AltaLink's responses. The AUC was satisfied that Midgard had sufficient information to complete its audit.

<u>Midgard Report</u>

The AUC provided a high level summary of the conclusions in the Midgard Report. Midgard divided the SW Project into three phases: project planning, approval, and execution. Midgard noted that the initial in-service date ("ISD") was set for February 28, 2007, requiring aggressive timelines after it submitted the proposal to provide services ("PPS") in June 2005. Midgard stated that it could not find evidence that AltaLink planned the steps necessary to build a transmission line on federally administered lands (i.e. First Nations Indian reserve lands), or that AltaLink understood the risks in proceeding with a right-of-way across federal lands at the time the PPS was submitted.

Midgard noted that the ISD for the SW Project was determined through a "top-down" process, driven by the interconnection needs of wind projects, rather than a "bottom-up" approach driven by the expected duration of project planning, approval and execution. As such, Midgard determined that AltaLink began procurement activities in order to start construction by March 2006. Midgard noted that due to the advanced procurement activities, the procurement and design activities were approximately 80 percent completed by the time the SW Project was halted in late 2006.

Midgard noted that the SW Project marked the first time AltaLink attempted to construct a transmission line across a federal right-of-way. Since the SW Project crossed the Blood Indian Reserve #148 and Piikani Indian Reserve #147, AltaLink required Indian and Northern Affairs Canada ("INAC") utility permits. A prerequisite to obtaining these permits is the successful completion of an environmental assessment under the *Canadian Environmental Assessment Act*. The development of terms of reference for the environmental assessment process was not completed until April 2006. The environmental assessment report ("EA") itself was submitted by AltaLink in October 2006.

In addition to the approval of the EA, Midgard noted that AltaLink required band council resolutions ("BCR") from the Blood and Piikani Band Councils to approve the detailed right-of-way plan before any INAC permits under section 28(2) of the *Indian Act* could be issued. Midgard noted that these BCRs were granted at the sole discretion of the Blood and Piikani Band Councils, with no timelines or legal requirements to oblige the issuance of a BCR.

Following the submission of the EA, INAC and other federal agencies began preparing a screening decision report on the EA, which was completed in June 2008. Midgard noted that the EA screening decision was completed approximately 27 months later than planned, and 34 months after AltaLink started its EA field studies in September 2005. Midgard noted that the time required to complete both of both of these activities went far beyond the originally planned approval dates.

BCRs for each of the reserves were provided on July 25, 2008 following the identification of traditional land use sites that required additional route modifications.

Midgard noted that AltaLink negotiated what it called "impact and benefits agreements" ("IBAs") with the Blood and Piikani Band Councils. This activity, in Midgard's opinion, extended several years beyond AltaLink's initially planned schedule.

Midgard stated that construction on the SW Project began on July 13, 2009, and that construction activities on behalf of AltaLink were undertaken by experienced and qualified contractors for large transmission projects. Midgard noted that the monthly construction reports did not document any significant project delays due to lack of available staff, or competence issues. However, Midgard noted a number of delays in construction were caused by environmental restrictions and some non-predictable conditions. These delays, according to Midgard, were exacerbated by AltaLink's compressed construction schedule that did not allow any schedule float to account for unplanned delays. Midgard itemized these delays as follows:

(a) Blockades on reserve lands;

(b) Re-routes on the Blood and Piikani reserves;

(c) Land access issues outside of reserves;

(d) Weather conditions and storm events; and

(e) Environmental discoveries.

Midgard noted that the initial cost estimate from AltaLink was $78.2 million in the 2005 PPS. At the facilities application stage, TCA 23 (a series of AltaLink documents noting scope and cost changes) projected a total cost of $138.4 million in 2007. Midgard stated that it treated the facilities application ("FA") estimate as the project baseline for costs, as this was the information available to the AUC in providing its approval of the SW Project in Decision 2009-028.

Midgard noted that TCA 24 was submitted in June 2009, just after approval of the SW Project, and just prior to construction. Midgard noted that TCA 24 contained several cost increases for transmission and substation labor, as well as right-of-way acquisition costs, and increased allowance for funds used during construction ("AFUDC") and engineering and supervision ("E&S") costs, totalling a $45.4 million increase.

TCA 25 was the final change document provided by AltaLink, following the first full year of construction, and following the construction shutdown during the bird nesting period. TCA 25 introduced incremental project costs for delays and modifications made to the SW Project through the first year of construction, as well as accounting for delays in construction. The final costs claimed for the project were reported by AltaLink as $224.6 million.

Midgard identified three key turning points in the execution of the SW Project:

(a) Initial Project Planning and Scheduling;

(b) December 2005 and February 2006 Facilities Applications on Reserve Routes; and

(c) August 2007 Consolidated Facilities Application.

<u>Variance from Baseline Costs</u>

The AUC, in providing its reasons on the final prudence determination, cited Decision 2014-283, which provides that a variance from a baseline estimate prepared at the PPS stage is not, in and of itself an indication of imprudence. Rather, the AUC characterized these variances as identifying areas for further investigation into the reasonableness of the owner's decision making.

<u>Initial ISD</u>

With respect to the initial ISD, the AUC held that projects are typically assigned to a TFO by the AESO, and that the TFO must keep the AESO informed of any issues respecting siting, timing and costs as the TFO becomes aware of them. However, the AUC held that this obligation was not without limitations, noting that the AESO is a sophisticated party with extensive knowledge of the siting and construction of transmission projects, as the Alberta transmission system planner. The AUC also held that the legislative scheme obligates a TFO to comply with the directions of the AESO, unless doing so would put its facilities or the safety of the TFO's employees or the public at risk. The AUC held that the AESO was aware of AltaLink's progress in securing INAC permits and other federal approvals. On this basis, the AUC held that AltaLink did not act imprudently, since there was no persuasive evidence on the record that the initial ISD of Febuary 2007 was unreasonable.

<u>Environmental Assessment</u>

With respect to the reasonableness of the environmental assessment planning process and related activities, the AUC noted that the time identified by Midgard as reasonable to obtain federal permitting approvals on First Nation lands was from two to five years.

Although the AUC held that the environmental process took considerably longer than first planned, AltaLink's efforts in hiring external expert assistance was reasonable in planning the environmental permitting process.

<u>Negotiations with First Nations</u>

With respect to reasonableness of negotiations with First Nations, the AUC noted Midgards' conclusion that filing the application which would cross First Nations reserves would provide negotiating leverage to the Blood and Piikani First Nations, in knowing that each had an effective right of veto over the planned SW Project route. The AUC also noted that Midgard suggested that holding off on filing such facility applications until the completion of the IBAs would have avoided an erosion of AltaLink's negotiating position.

Both AltaLink and PRDL submitted that Midgard's conclusions implied that AltaLink should have withheld information from First Nations to maintain negotiating leverage. Both AltaLink and PRDL submitted that such conclusions should be dismissed out of hand, since such actions would be contrary to law, and would imply that AltaLink advance a demonstrably inferior route to gain leverage over First Nations.

AltaLink also submitted that the Blood and Piikani First Nations continued to express support for the preferred route option on the SW Project throughout the negotiations.

PRDL submitted in argument that the analogies used by Midgard in depicting consultation and negotiation processes with First Nations were concerning. PRDL submitted that Midgard's likening of the consultation and negotiation process to a "candy toss" or "pushing a chequebook across the table and say[ing] fill in your number" were concerning, and wholly inappropriate.

The AUC held that, payment of access fees to landowners in construction of a transmission project is a cost of doing business. The AUC noted that under provincial processes, such fees are still negotiated with landowners, and may be the subject of proceedings before the Alberta Surface Rights Board. However, the AUC also noted that the Alberta Surface Rights Board does not have the authority to issue a right of entry order across First Nations lands, but that this fact was not unknown to the AESO, AUC or AltaLink in proceeding with the preferred route.

The AUC further held that, based on the facts before it, the Blood and Piikani First Nations, as sophisticated investors, would have had knowledge of the preferred route as early as 2004 with the AESO's filing of the original needs identification document. The AUC therefore held that AltaLink's actions in this respect were not imprudent.

<u>AFUDC and E&S Costs</u>

With regard to AFUDC and E&S costs, the AUC noted that prior to the hearing, AltaLink had filed a supplemental analysis dated September 30, 2015 using actually incurred costs of $5.9 million for AFUDC and E&S costs. The AUC noted that Midgard accepted these revised figures as filed, and revised its proposed cost impacts accordingly.

The AUC determined that, while under normal commercial circumstances, it would have been unreasonable for AltaLink to begin material procurement so far in advance of construction. However, the operating environment at the time was such that the AESO was concerned about availability of materials and services, and issued direction letters to AltaLink on February 15, 2006 ordering AltaLink to proceed with early procurement pursuant to section 35 of the *Electric Utilities Act*. Accordingly, the AUC held that it was clear that the AESO ordered AltaLink to begin early procurement, and that in the circumstances, AltaLink was obligated to comply. As such, the AUC determined that AltaLink's costs for AFUDC and E&S were prudently incurred.

<u>Timing of Facility Application</u>

The AUC determined that the escalation costs associated with the delays in the SW Project caused by premature filing of the facilities application were prudently incurred as well, holding that AltaLink did what it reasonably could at the time to advance the facilities application and permitting process.

<u>Project Execution and Construction Costs</u>

On matters related to project execution and construction costs, AltaLink submitted that it faced unexpected challenges in executing the SW Project, and that it made management decisions to respond to those challenges. AltaLink's decisions at the time they were made were reasonable and prudent. AltaLink's use of helicopters to erect the towers for the SW Project was considered reasonable by Midgard, and that such measures reflected good industry practice when access to construction sites is an issue. AltaLink also noted that Midgard found AltaLink's decision effectively mitigated increased standby charges for construction crews, and assisted in mitigating further scheduling delays.

AltaLink also submitted that Midgard found AltaLink's practice of standing down construction crews during blockades was reasonable to protect worker safety.

PRDL submitted that the testimony of Midgard was instructive on the reasonableness of AltaLink's construction costs, wherein Midgard stated that "construction is war" and that decisions taken by the responsible entity to reduce larger ticket items is a reasonable response.

The AUC determined that AltaLink's decision to mitigate cost and schedule impact from various blockades by using off-site assembly yards and employing helicopters for transportation produced positive results for the SW Project's schedule and budget. The AUC also held that AltaLink could not have reasonably foreseen the opposition that subsequently arose during project construction. Accordingly, the AUC held that it could not find that AltaLink's use of helicopters to maintain its ISD to be imprudent.

Rate Base Addition

The AUC, in making its findings with respect to rate base addition amounts, held that, while the magnitude of the cost variance in this project was a cause for concern, it held that such a variance was not in and of itself an indication of imprudence, but rather an area for further investigation as to the cause and reasonableness of the decision making process.

In finding that AltaLink's decision making was not imprudent, the AUC held that AltaLink's claimed costs for the SW Project were therefore approved as filed. The interim amount approved as a placeholder in Decision 2013-407 was therefore approved on a final basis, and AltaLink was not required to provide any further reconciliation of SW Project amounts.

AltaGas Utilities Inc. 2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application (Decision 20522-D02-2016)
Capital Tracker – True-up and Forecast

AltaGas Utilities Inc. ("AltaGas") filed an application with the AUC for approval of its 2014 capital tracker true-up and 2016-2017 capital tracker forecast application and associated schedules.

In Decision 2014-357, the AUC approved AltaGas' application for a 90 percent placeholder K factor for 2015 in the amount of $3.14 million on an interim basis. Similarly, in Decision 20823-D01-2015, the AUC approved AltaGas' application for a 2016 K factor placeholder in the amount of $4.86 million on an interim basis.

Capital tracker applications are part of the performance based regulation ("PBR") plans originally approved by the AUC on a five-year term in Decision 2012-237.

The PBR framework essentially provides a formula mechanism to adjust rates annually, using inflation (I Factor) less an offset (X Factor) to reflect the productivity improvements the utility can expect to achieve during the test period, as well as growth in forecast billing determinants (Q factor). However, the PBR framework also requires certain adjustments, including amounts to fund necessary capital expenditures (K Factor), flow-through costs to be recovered directly from the consumer (Y Factor), and material events for which the company has no other reasonable cost recovery mechanism (Z Factor). Capital tracker costs form part of the K Factor adjustments within the PBR mechanism.

Projects or programs meet the following three criteria in order to be eligible for capital tracker treatment:

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

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

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

Project Groupings

AltaGas submitted that its project groupings for capital tracker purposes remain largely unchanged, and are consistent with groupings approved by the AUC in Decisions 2013-435 and 2014-373.

No party objected to AltaGas' proposed project groupings.

The AUC held that AltaGas' proposed project groupings continue to be reasonable, and were therefore approved as filed.

The AUC noted that unless the driver for a previously approved ongoing capital tracker project or program has changed, the AUC would not undertake a reassessment under Criterion 1 or Criterion 2, but would undertake an assessment to ensure compliance with Criterion 3. Any new capital tracker programs are required to satisfy all of Criterion 1, Criterion 2 and Criterion 3 to receive capital tracker treatment.

Projects and Programs previously approved

i. Pipeline Replacement Program

AltaGas applied for continued capital tracker treatment of its pipeline replacement program, which was previously approved in Decision 2012-091 and 2010-012, and most recently in Decision 2014-373. AltaGas noted that the program provides for the replacement of three types of pipe:

(a) Polyvinylchloride ("PVC") pipe;

(b) Non-certified and interim certified polyethylene ("PE") pipe; and

(c) Pre-1957 steel pipe.

AltaGas submitted that it replaces each type of pipe according to a risk assessment matrix taking into account the impact of failure and the likelihood of failure. AltaGas forecasted the replacement of approximately 52.9

kilometers of PVC pipe in 2015, 111.9 kilometers of PVC pipe in 2016, and 131.4 kilometers of PVC pipe in 2017. AltaGas submitted that recent improvements in resourcing and internal processes should result in AltaGas being able to complete the replacement of PVC pipe by the end of 2018.

With respect to non-certified PE pipe, AltaGas submitted that it planned to replace 27.1 kilometers of non-certified PE pipe in 2015, 44.3 kilometers in 2016, 83.6 kilometers in 2017. AltaGas further anticipated replacement lengths of 114.1 kilometers, 163.8 kilometers, and 160 kilometers in 2018, 2019 and 2020 respectively.

With respect to pre-1957 steel pipe, AltaGas noted that it still has approximately 98.8 kilometers of pre-1957 high pressure steel pipe on its system. AltaGas indicated that 85.6 kilometers is scheduled for replacement, with 12.4 kilometers slated for replacement under a different project, and the remaining 0.8 kilometers will be abandoned. AltaGas anticipates replacing all pre-1957 steel pipe by 2019.

ii. Station Refurbishment Program

AltaGas applied for continued capital tracker treatment of its station refurbishment program, which was previously approved in Decision 2012-091 and 2010-012, and most recently in Decision 2014-373. AltaGas submitted that it operates 686 stations in Alberta, approximately 30 percent of which were installed in the 1950s through 1970s, and are equipped with obsolete parts or do not conform to modern pipe configurations. AltaGas submitted that it would prioritize station refurbishments according to a priority list based on risks to worker safety and potential for failure. AltaGas stated that it operates three types of stations:

(a) Purchase meter stations (“PMS”);

(b) Town border stations (“TBS”); and

(c) Post regulator stations (“PRS”).

AltaGas’ PMS were the largest and most complex stations of the three types. According to AltaGas’ risk assessment matrix, it identified 39 PMS and 40 TBS over 25 years old as the highest priority for refurbishment based on throughput, station age, obsolescence and design, and site specific issues (e.g. flood prone, security, etc.) AltaGas planned to complete 41 PMS, 33 TBS and 27 PRS refurbishments from 2015 through 2018, and planned to complete all refurbishments by the end of 2018.

iii. Gas Supply Program

AltaGas submitted that its gas supply program was previously approved by the AUC in Decisions 2012-091 and was most recently approved in Decision 2014-373. AltaGas submitted that the purpose of its gas supply program was to assess the gas supply across the AltaGas system to identify risks to service quality and safety. AltaGas noted the difficulty of predicting such issues due to the variety of causes, and the unique nature of each project. AltaGas submitted that it identified two gas supply projects for its forecast term:

(a) Gas supply issues to the Barrhead/ Westlock/ Morinville (“BWM”) area in 2016, as one of AltaGas’ third party suppliers intends to discontinue operation of its high pressure supply line servicing the BWM area; and

(b) The replacement of the gas supply to the town of Calmar, which is serviced by a combination of pre-1957 steel pipe and non-certified PE and PVC pipe, due to severe corrosion observed on the nearby pipes.

<u>Project Assessments under Criterion 1</u>

The AUC noted that AltaGas did not apply for any new capital tracker programs, but did apply for approval of specific projects within each of its pipeline replacement, station refurbishment and gas supply programs. Each of the projects applied for by AltaGas fall within three broad categories:

(a) Projects completed in 2013, not approved for capital tracker treatment in Decision 2014-373 and reapplied for in the application on an actual basis;

(b) Projects previously approved in Decision 2014-373 for 2014 on a forecast basis and fully or partially completed in 2014; and

(c) Projects to be implemented in 2016 or 2017 that have not been previously approved for capital tracker treatment.

The AUC held that there was no evidence that any of the following projects were not necessary:

(a) Those projects completed in 2013; and

(b) Those projects previously approved for 2014 and now proposed for true-up.

The AUC also held that there was no evidence on the record that the forecast projects for 2016 and 2017 were not required to maintain service reliability, quality and safety at adequate levels. Accordingly, the AUC held that these three categories of projects satisfied Criterion 1.

2016-2017 Forecast Capital Tracker Projects

AltaGas submitted that for forecasting its costs, it applied a regression process to estimate future costs using a three year set of historical costs divided by project type.The results of its regression costing approach fit its historical data very well, noting that tendered contractor costs have a very high correlation. AltaGas noted that, at the time a project area is defined, little is known about the project aside from the length of the project and the scope of services involved. As a result, AltaGas submitted that its regression analysis provided the best estimate of project costs without having to do field reconnaissance too far in advance.

i. Pipe Replacement Program

AltaGas submitted that PVC pipe replacement projects would cost approximately $8.2 million in 2016, and $10.3 million in 2017, based on its linear regression model and an inflation factor of 4.56 percent. For non-certified PE pipe replacement, AltaGas forecasted additions of approximately $4.2 million for 2016, and $7.8 milion for 2017, using the same methodology. Pre-1957 steel pipe forecast replacement costs were estimated at $12.2 million for 2016, and $14.7 million for 2017 using the same methodology.

None of the parties to the proceeding opposed AltaGas' forecast costs for PVC, non-certified PE, and pre-1957 steel pipe replacement projects.

ii. Station Refurbishment Program

AltaGas forecasted its 2016-2017 station refurbishment program costs as follows:

(a) PMS refurbishments - $312,200 for 2016 per station and $318,800 for 2017 per station;

(b) TBS refurbishments - $211,200 for 2016 per station and $215,700 for 2017 per station; and

(c) PRS refurbishments - $34,600 for 2016 per station and $35,200 for 2017 per station.

AltaGas stated that its forecast costs were escalated by its standard 2015 costs, inflated by 2.65 percent and adding an overhead rate of 5.36 percent. In total, AltaGas stated that it planned to complete 19 station refurbishments in 2016 for a total cost of $3.9 million and 24 stations in 2017 for a total cost of $3.8 million.

None of the parties to the proceeding opposed AltaGas' forecast costs for station refurbishments.

The AUC held that while the regression model was a useful forecasting tool, if parties were to properly test the forecast costs, AltaGas' regression model was required to provide more information. Notably, the AUC held that a complete understanding was not possible unless detailed descriptions of the variables used and the models themselves were provided. Consequently, the AUC determined that the forecasts could not be reproduced, but that the steps taken by AltaGas to forecast costs more accurately were reasonable and approved for the purposes of this decision. Accordingly, the AUC found that the forecast cost information was reasonable and met the requirements of Criterion 1.

The AUC held that the detailed cost breakdown for station refurbishment forecasts were comparable to those approved in Decision 2014-373, adjusted for inflation. The AUC noted that based on the information provided by AltaGas, the station refurbishment program costs satisfied Criterion 1.

iii. Gas Supply Program

AltaGas' forecast costs for its gas supply program were $3,094,500 for 2016 and $2,069,894 for 2017. AltaGas requested that the costs associated with its gas supply program for the BWM area receive placeholder treatment, pending the outcome of AltaGas considering alternatives to replacing or building new assets to connect gas supply to Calmar and the BWM area. AltaGas submitted that placeholder treatment was necessary, as a denial of such placeholder treatment would negatively impact AltaGas' ability to secure financing.

The Office of the Utilities Consumer Advocate ("UCA") requested an explanation from AltaGas regarding its forecast, and requested that AltaGas provide full disclosure regarding alternative options. AltaGas replied that it may not be possible or permissible for it to fully disclose such information at the time of the hearing as it was still in negotiations with a third party supplier. However, AltaGas noted that it may be in a position to fully disclose its business case at the time of its 2015 capital tracker true-up application.

The UCA requested that the AUC deny placeholder treatment of the gas supply program costs, given that AltaGas had not submitted a business case in compliance with Criterion 1. The UCA also submitted that using a placeholder amount effectively defeats the purpose of the requirement. The UCA submitted that if AltaGas felt the program was necessary, it should either complete a business case, or complete the project and apply for capital tracker treatment of its committed costs.

The Consumers' Coalition of Alberta ("CCA") supported the UCA's argument, submitting that AltaGas provided no evidence regarding the need for approving the forecast costs, apart from a statement that a denial would impact AltaGas' finances. The CCA requested that AltaGas be directed to provide a business case and engineering study, and provide further evidence of the financial effects of such a denial to AltaGas' finances.

None of the parties opposed AltaGas' forecast costs related to the Calmar gas supply program.

The AUC noted that it had previously approved a forecast placeholder for AltaGas' gas supply program in Decision 2014-373, noting that it was determined to be a reasonable approach as at least one gas supply project would arise, although the particulars were not known sufficiently in advance to provide detailed costing information. The AUC noted that the placeholder amount was approved based on a historical review of gas supply projects in the three years prior. Actual gas supply program expenditures are then trued-up against actual project costs in subsequent applications.

The AUC accepted AltaGas' evidence that the gas supply project in the BWM area would be required, but that it did not file a business case due to ongoing negotiations. The AUC also accepted that AltaGas' forecast costs of $3.1 million for the gas supply project in the BWM area would impose some degree of financial hardship on AltaGas. However, the AUC held that placeholder funding should continue to be based on the historical three year average of gas supply program costs (with the exception of the Calmar gas supply project.) The AUC therefore approved a gas supply program placeholder for 2016 of $661,250 based on the historical three year average of gas supply project costs.

With respect to the Calmar gas supply project, the AUC noted that AltaGas provided a fully explained business case, and a forecast cost of the project. The AUC determined that the information provided by AltaGas in respect of the Calmar gas supply project in 2017 was reasonable, and therefore approved a placeholder of $2.07 million for the Calmar gas supply project.

Accounting Test Under Criterion 1

The AUC noted that the accounting test under Criterion 1 is meant to determine whether a program proposed for capital treatment falls outside the normal course of business. The AUC stated that this is achieved by demonstrating that the revenue requirement growth under the I-X mechanism of PBR would be insufficient to recover the costs necessary for the capital tracker programs.

AltaGas submitted that for the accounting test for the 2014 true-up, it applied an I-X index of 1.59 percent, and a Q factor (i.e. billing determinant growth) of 1.70 percent approved in Decision 2013-465. For the 2016 and 2017 forecast periods, AltaGas applied 1.49 percent as a placeholder for the I-X mechanism and a Q factor of 1.72 percent for 2016, and 1.49 percent as a placeholder for the I-X mechanism and a Q factor of 1.78 percent for 2017.

None of the parties objected to AltaGas' proposed methodologies or assumptions used in the accounting test.

With respect to the I-X index and Q factors, the AUC reminded AltaGas that it expressed a preference to use an I-X index that was previously approved in a PBR rate adjustment proceeding and a Q factor based on an approved billing determinant forecast, where possible. The AUC held that AltaGas' accounting test methodology was reasonable and consistent with the methodology approved in Decision 2013-435. The AUC also held that AltaGas applied the correct I-X and Q factor values for its 2014 true-up, and that the forecast values for 2017 were acceptable, as the final approved numbers for 2017 were not available. However, for 2016 values, the AUC directed AltaGas to apply the forecast billing determinants approved in Decision 20823-D01-2015 in its compliance filing to this decision.

Subject to the adjustments directed, the AUC determined that it was satisfied that AltaGas' accounting test method could demonstrate that the forecast expenses were outside the normal course of business, in compliance with Criterion 1.

Criterion 2

As noted above, the AUC held that unless the driver behind a project or program changes, previously approved programs would not be required to demonstrate compliance with Criterion 2 again. AltaGas confirmed that none of the drivers for its capital tracker programs changed.

The AUC therefore held that the projects and programs applied for continue to satisfy Criterion 2.

Criterion 3

The AUC noted that Criterion 3 applies in two tiers. The first tier materiality threshold asks if each project would meet a four basis point impact threshold on revenue requirement. The second tier examines whether, in aggregate, all of the capital trackers would exceed a 40 basis point impact threshold on revenue requirement.

AltaGas submitted its capital tracker costs all exceeded the materiality thresholds required by Criterion 3. AltaGas submitted that the four basis point and 40 basis point thresholds for 2014 true-up costs were $31,816 and $318,156, respectively by escalating its approved 2012 amount by the 2013 and 2014 I-X mechanism values.

For the 2016-2017 forecast period, AltaGas submitted the following basis point thresholds by escalating its approved costs by its current I-X index and Q factors as follows:

(a) Four basis point threshold: $32,771 for 2016 and $33,259 for 2017; and

(b) 40 basis point threshold: $327,707 for 2016 and $332,590 for 2017.

None of the parties took issue with AltaGas' calculation of its materiality thresholds.

The AUC held that while it accepted AltaGas' forecasting methodology, and noted that AltaGas' calculations of the materiality thresholds were reasonable, the AUC directed AltaGas to refile its materiality thresholds for 2016 using the I-X index and Q factor values approved in Decision 20823-D01-2015 to calculate the first and second tier materiality thresholds.

K Factor Adjustments

As a result of AltaGas' requested capital tracker true-up and forecast costs, AltaGas requested the following K Factor amounts:

(a) 2014 K factor true-up reduction of $193,806;

(b) 2016 forecast K factor addition of $5,854,585; and

(c) 2017 forecast K factor addition of $8,483,831.

AltaGas proposed to allocate these reductions and additions using the same methodology approved in Decision 2014-373.

None of the parties took issue with AltaGas' proposed amount or allocations of K factors.

The AUC held that the K factor amounts were correctly calculated and were reasonable. However, for the 2016 and 2017 amounts, the AUC directed AltaGas to refile its requested K Factor amounts to reflect the 2016 I-X index and Q factor as approved in Decision 20823-D01-2015, and to reflect the revised gas supply placeholder. All other K factor amounts were approved as filed.

Order

In the result, the AUC directed AltaGas to file a compliance filing reflecting the AUC's directions by February 29, 2016.

Revision of AUC Rule 027: Specified Penalties for Contravention of Reliability Standards (Bulletin 2016-01)
Bulletin – Rule 027 Revisions

On January 26, 2016, the AUC released a bulletin advising that it approved amendments to AUC Rule 027: *Specified Penalties for Contravention of Reliability Standards* ("*Rule 27*"). The bulletin notes that the amendments become effective on March 1, 2016.

The AUC stated that while its usual practice is to invite comments regarding amendments to *Rule 27*, the changes were deemed administrative in nature, and did not necessitate consultation. The changes to *Rule 27* involved the addition of new and amended reliability standards to the penalty table, and the removal of replaced or retired reliability standards.

A red-lined copy of *Rule 27*, outlining the amendments can be found here.

Revision of AUC Rule 007 Respecting Environmental Updates and Needs Identification Documents (Bulletin 2016-02)
Bulletin – Rule 007 Revisions

The AUC released this bulletin as a follow-up to Bulletin 2015-14 in which the AUC identified a need to work with stakeholders to identify improvements and revisions to Rule 007: *Applications for Power Plants, Substations, Transmision Lines, Industrial System Designations and Hydro Developments* ("*Rule 7*") to reflect:

(a) Updates for environmental requirements, including checklists for transmission line and substations projects;

(b) Streamlined requirements for needs identification documents; and

(c) Elimination of applications for approval of certain isolated generating units.

After taking into account stakeholder comments, the AUC approved changes to *Rule 7*. These changes became effective on February 1, 2016. All of the materials related to the changes to *Rule 7* can be found here.

ATCO Electric Ltd. 2016 Interim Transmission Facility Owner Tariff (Decision 21051-D01-2016)
TFO Tariff – Interim Revenue Requirement

ATCO Electric Ltd. ("ATCO") applied to the AUC for approval of an interim revenue requirement of $840.5 million (or $70.04 million monthly) effective January 1, 2016. The requested revenue requirement is equivalent to 100 percent of the $214.4 million increase in ATCO's forecasted 2016 revenue requirement over its 2015 interim revenue requirement of $626.13 million.

ATCO sought approval of the 2016 interim tariff as a result of its outstanding 2015-2017 general tariff application, filed on March 16, 2015, which sought revenue requirements of $694.3 million for 2015, $810.8 million for 2016, and $913.3 million for 2017.

ATCO cited two criteria for evaluating the need for an interim rate increase: quantum and need factors; and public interest factors.

With respect to quantum and need, ATCO submitted that its requested revenue requirement increase of $214.4 million was substantial and material, which necessitated additional funds during 2016. ATCO therefore requested 100 percent of its applied-for interim tariff, or in the alternative, 90 percent, including contested items and issues to offset the risk of a credit downgrade.

ATCO also submitted that the approval of its requested interim rate increase would allow for a gradual increase to rates, which would avoid both intergeneration equity concerns and rate shock to consumers.

The Utilities' Consumer Advocate ("UCA") recommended an interim tariff level equal to 50 percent of the requested increase for 2016 rates. The UCA cited Decision 20556-D01-2015 wherein the AUC held that it preferred "gradualism" in transitional rates, and therefore adopted an intermediate position between current rates and proposed final rates in a range between 50 and 75 percent of the requested increase on an interim basis.

The AUC held that it would consider the application on its own merits. In so doing, the AUC held that ATCO did not provide any indication of potential impacts an approval of 90 percent of the requested increase would have on its credit rating. Consequently, the AUC determined that it could not assess the importance of the interim rate needed for ATCO's ability to insulate its credit metrics.

However, the AUC noted that the accumulated shortfall from interim and requested rates represented a material amount with a potential for rate shock to consumers, and therefore held that relief was warranted at 90 percent of ATCO's proposed revenue requirement.

The AUC therefore approved ATCO's 2016 TFO tariff on an interim basis at $63.2 million per month, effective January 1, 2016 until otherwise directed by the AUC.

NATIONAL ENERGY BOARD

Fall 2015 Reports of the Commissioner of the Environment and Sustainable Development – Report 2 Oversight of Federally Regulated Pipelines
Federally Regulated Pipelines

In January 2016, the Commissioner of the Environment and Sustainable Development ("CESD") released its fall 2015 reports. Report 2 of these fall 2015 reports examines federally regulated pipelines (the "CESD Report").

The CESD Report notes that Canada's pipeline sector had entered a period of increased activity and scrutiny, driven mainly by rapid growth in oil sands development. The total investment value of new federally regulated pipeline projects, either approved by the NEB, or currently under consideration, is approximately $25 billion.

With increased activity, the level of public attention to pipeline projects has increased. The CESD Report cites recent incidents such as at Kalamazoo, Michigan and near Fort McMurray, Alberta, although these were not NEB regulated pipelines.

The CESD Report stated that the NEB undertook a National Engagement Initiative to listen to stakeholder suggestions on how to best adjust its approach to pipeline safety and environmental protection, among other items.

The focus of the CESD Report was an examination of the following three issues:

(a) Whether the NEB was verifying that regulated companies were complying with pipeline project approval conditions and regulations;

(b) Whether the NEB was prepared to fulfill its role in emergency response, including verification that companies' emergency manuals were complete and up to date; and

(c) Whether the NEB had assessed its capacity to deliver on its responsibilities.

A full copy of the CESD Report can be accessed here.

Tracking Company Compliance

Overall, the CESD Report found that the NEB's tracking of company compliance with conditions imposed was generally inadequate, despite having taken steps to improve follow-up processes on noncompliances. The CESD Report also found that the board has taken steps to improve public access to information on compliance with regulatory conditions, but has not taken similar steps for pipeline approval conditions.

The CESD Report noted that the NEB's tracking and documentation of pipeline conditions was adequate for about half of the cases examined (25 of 49 cases). In the cases where the tracking and documentation was inadequate, the CESD Report noted that the NEB's tracking was either inaccurate, out of date, or missing key documents. In some cases, the CESD Report noted that the files may have been lacking in a final analysis of a company's submissions or a conclusion document regarding whether the condition had been fully satisfied.

The CESD Report recommended that the NEB systematically track compliance with pipeline approval conditions and document such oversight work, including notifications regarding the status of achievement on each condition.

The NEB agreed with the CESD Report recommendation, stating that by December 2016, the NEB will clarify and enhance processes so that company compliance with pipeline approval conditions are tracked in a systematic fashion.

With respect to follow-ups on compliance deficiencies, the CESD Report examined 42 of the NEB's 252 compliance verification activities since 2011. In these 42 instances, the CESD Report noted 22 instances in which compliance verification was not consistently or properly documented, as the documents were either out of date, inaccurate, not timely, or missing a final conclusion on company compliance, among other findings. In one instance, the CESD Report detailed that one NEB inspection had detected numerous liquid sulphur leaks. While the NEB obtained a corrective action plan from the company responsible, the CESD Report noted that it could not conclude whether the corrective action plan had actually been implemented.

The CESD Report recommended that the NEB systematically verify that companies implement corrective actions to noncompliances in a timely manner, and for the NEB to similarly notify companies when the corrective action has been completed.

The NEB agreed with the CESD Report recommendation, noting that it has already taken significant steps to enable greater systematic verification of corrective action implementation. The NEB stated that by June 2016 it will clarify and enhance its processes for corrective action follow-ups.

NEB Information Systems for Tracking Compliance

The CESD Report concluded that the NEB faced system-wide challenges with its information management tools used to track company compliance. The CESD Report noted that the NEB employed several different systems that were not integrated with one another, or were outdated or inefficient. The CESD Report noted that this lack of integration increased administrative burdens on staff and increased the risk of human error in processing documentation. The CESD Report also noted that in 2009 and 2011, the NEB took steps to improve information management systems, but that implementation of programs and projects to improve information management were incomplete or had no formal funding in place.

The CESD Report recommended that the NEB assess and address its data management needs to align with its critical business processes.

The NEB agreed with the CESD Report recommendation, noting that it also took steps to modernize its systems for critical business processes, including the creation of an Event Reporting System, and an electronic Operations Regulatory Compliance Application ("ORCA"). The NEB stated that the development of these systems has clarified data and information needs for incident reporting and inspections. The NEB stated that it would implement further steps to improve its information and data management in the 2016-2017 fiscal year.

Public Access to Information on Companies' Compliance

The CESD Report concluded that while the NEB had taken steps to improve public access to information on company compliance with regulatory requirements, improvement was needed with respect to company compliance with pipeline approval conditions. The CESD Report noted that the Safety and Environmental Performance Dashboard on the NEB website made such data publicly accessible. However, the CESD Report noted that public access to companies' compliance with pipeline approval conditions was hindered by the manner in which the information was presented. The CESD Report noted that many of the pipeline approval conditions were contained within the Regulatory Document Index on the NEB website, which was complicated and difficult to navigate for the general public.

The CESD Report recommended that the NEB provide improved public access to information about company compliance with pipeline approval conditions. Specifically, the CESD Report recommended that the NEB website incorporate a user-centred design that the public can access efficiently.

The NEB agreed with the recommendation of the CESD Report, noting that by December 2016, it would begin to implement its plan to facilitate access to pipeline approval conditions and compliance monitoring to the public. The NEB noted that this work would take place in conjunction with the NEB's commitment to clarify and enhance its tracking and documentation of pipeline approval conditions.

Emergency Preparedness

The CESD Report concluded that although the NEB was fulfilling its role as the lead federal agency on pipeline emergency response, that there were important opportunities for improvement. The CESD Report noted that one third of the companies' emergency procedures manuals still lacked important information since the CESD's last audit of the NEB. In a previous audit, the CESD noted that the NEB had identified a number of gaps and deficiencies in emergency preparedness manuals prepared by pipeline companies, but the CESD noted that there was little indication that the NEB had followed up with these companies to ensure that the deficiencies had been corrected.

Consolidation of Risk Assessments into Emergency Management Plans

The CESD Report concluded that, due to the NEB's ideal position as the lead federal regulator of pipeline projects, it should consolidate the results of its various risk assessments from pipeline companies into an "all-hazards risk assessment" to better inform its emergency management activities. The CESD Report stated that such a consolidation may assist in identifying which pipelines require additional oversight and controls. The CESD Report also recommended implementing such a consolidation in consultation with other federal energy regulatory agencies, such as Natural Resources Canada.

The NEB agreed with the CESD Report's recommendation. The NEB also stated that it will consolidate its various risk assessment activities related to its mandate into a central document by June 2016, and will consult with Natural Resources Canada as appropriate.

Capacity to Recruit and Retain Key Staff

The CESD Report found that although the NEB has taken steps to address a number of issues, it has experienced challenges in recruiting and retaining skilled and experienced staff, especially so for high demand job families, such as engineering. The CESD report noted that following changes to the *National Energy Board Act* in 2013-2014, the NEB's workload increased due to more frequent inspections and compliance activities, as well as an increase in the number of pipeline applications.

The CESD Report noted that the competitive energy industry job market also made the staffing of mid-level engineering positions persistently difficult.

The CESD Report noted the NEB took several steps to address these challenges, by taking measures such as work-life balance accommodations and promoting experienced staff to higher level positions in acting assignments, as well as hiring consultants as needed.

The CESD Report recommended that the NEB review its overall resource assessment and explore further avenues to address and resolve staffing challenges.

The NEB agreed with the CESD Report recommendation, noting that such challenges are not unique in the energy industry, and that it will continue to seek constructive and flexible solutions to attract and retain staff.

LNG Canada Development Inc. Application for a 40-Year Licence to Export Natural Gas as Liquefied Natural Gas – Reasons for Decision (January 7, 2016)
Licence to Export – Liquefied Natural Gas

LNG Canada Development Inc. ("LNG Canada") applied to the NEB pursuant to section 117 of the *National Energy Board Act* ("*NEB Act*") for a licence to export natural gas in the form of liquefied natural gas ("LNG") on the following terms:

(a) 40 year licence, starting on the date of the first export;

(b) A 6.1 percent annual tolerance, and a maximum annual export quantity of 38.056 billion cubic metres ($10^9 m^3$) or 1,344 billion cubic feet (bcf) of natural gas;

(c) A maximum term quantity of 1,494 $10^9 m^3$ (52,729 bcf) of natural gas;

(d) A point of export at the loading arm of a proposed natural gas liquefaction terminal in Kitimat, British Columbia; and

(e) An early expiration clause where the licence will expire on December 31, 2022, unless exports have commenced by that date,

(the "Export Licence").

LNG Canada had previously applied to the NEB in 2012 for the Export Licence subject to a 25 year term, for which it received approval in February 2013 under Licence GL-300. However, due to the passage of the *Economic Action Plan 2015 Act*, section 119.01(1.1) of the *NEB Act* was amended to allow exports on a 40 year term.

The NEB approved the Export Licence as filed, and revoked Licence GL-300.

Canada Stewart Energy Group Ltd. Application for a Licence to Export Gas as Liquefied Natural Gas Reasons for Decision (January 7, 2016)
Licence to Export – Liquefied Natural Gas

Canada Stewart Energy Group Ltd. ("Stewart") applied to the NEB pursuant to section 117 of the *National Energy Board Act* ("*NEB Act*") for a licence to export natural gas in the form of liquefied natural gas ("LNG") on the following terms and conditions:

(a) A 25-year licence, starting on the date of first export;

(b) A 15 per cent annual tolerance, a maximum annual export quantity of 47.56 billion cubic metres ($10^9 m^3$) or 1,679 billion cubic feet (Bcf);

(c) A maximum term quantity of 989.3 $10^9 m^3$ (34,923 Bcf) over the term of the licence;

(d) A point of export at the proposed natural gas liquefaction terminal to be located near Stewart, British Columbia; and

(e) An early expiration clause where the licence will expire ten years from the date of Governor in Council approval of the issuance of the licence if exports have not commenced on or before that date,

(the "Export Licence").

Stewart submitted that the quantity of gas it sought to export did not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada as required by section 118 of the *NEB Act*. Stewart submitted that in determining the supply and demand forecast, it only considered its own export volumes, submitting that no LNG export facility has reached a final investment decision.

Stewart submitted that the North American market was generally efficient, transparent, liquid, and capable of responding to changes in supply and demand through price. Stewart also submitted a demand sensitivity analysis considering a 20 percent increase in Canadian demand over the term of the Export Licence, and found that it would not change its overall conclusions of adequate supply for domestic markets.

The NEB agreed with Stewart, holding that the exports did not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada as required by section 118 of the *NEB Act*. The NEB also held that the estimates provided in the application were generally consistent with the NEB's own monitoring effects.

The NEB therefore granted the Export Licence to Stewart as applied for.

Kitsault Energy Ltd. Application for a Licence to Export Natural Gas as as Liquefied Natural Gas Reasons for Decision (January 21, 2016)
Licence to Export – Liquefied Natural Gas

Kitsault Energy Ltd. ("Kitsault") applied to the NEB pursuant to section 117 of the *National Energy Board Act* ("*NEB Act*") for a licence to export natural gas in the form of liquefied natural gas ("LNG") on the following terms and conditions:

(a) A term of 20 years starting on the issue date of the licence and not extending beyond 31 December 2035;

(b) A 15 per cent annual tolerance, a maximum annual export quantity of 32.2 billion cubic metres (10^9m^3), or 1 136 billion cubic feet, of natural gas;

(c) A maximum term quantity of 644 10^9m^3 (22.7 trillion cubic feet) of natural gas over the term of the licence, including tolerance;

(d) A point of export at the outlet of the loading arm of the natural gas liquefaction terminal to be located near Kitsault, British Columbia; and,

(e) An expiration clause where, unless otherwise authorized by the Board, the Licence will expire at the end of 31 December 2024 if LNG exports have not commenced on or before that date,

(the "Export Licence").

Kitsault submitted that the quantity of gas it sought to export did not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada as required by section 118 of the *NEB Act*. Kitsault submitted that in determining the supply and demand forecast, it only considered its own export volumes, submitting that no LNG export facility have reached a final investment decision.

Kitsault submitted that the North American market was generally efficient, transparent, liquid, and capable of responding to changes in supply and demand through price. Kistault also submitted that the resource base in Western Canada was very large, such that there were sufficient reserves for domestic demand over the 20-year term, as well as surplus for additional growth for either excess domestic demand or other export projects as well. Kitsault submitted a demand sensitivity analysis considering a 20 percent increase in Canadian demand over the term of the Export Licence, and found that it would not change its overall conclusions of adequate supply for domestic markets.

The NEB agreed with Kitsault, holding that the exports did not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada as required by section 118 of the *NEB Act*. The NEB also held that the estimates provided in the application were generally consistent with the NEB's own monitoring effects.

The NEB therefore granted the Export Licence to Kitsault as applied for, in addition to relieving Kitsault of filing information requirements for gas export licence applications set out in Section 12 of the *National Energy Board Act Part VI (Oil and Gas Regulations)*.

AltaGas DCLNG General Partner Inc., on behalf of AltaGas DCLNG Lease Limited Partnership Application for a Licence to Export Liquefied Natural Gas Reasons for Decision (January 14, 2016)
Licence to Export – Liquefied Natural Gas

AltaGas DCLNG General Partner Inc., on behalf of AltaGas DCLNG Lease Limited Partnership ("AltaGas DCLNG") applied to the NEB pursuant to section 117 of the *National Energy Board Act* ("*NEB Act*") for a licence to export natural gas in the form of liquefied natural gas ("LNG") on the following terms and conditions:

(a) A term of 25 years starting on the issue date of first export;

(b) A maximum annual export quantity of 10.3 billion cubic metres (10^9m^3), or 365 billion cubic feet, of natural gas;

(c) A maximum term quantity of 258.2 10^9m^3 (9,125 billion cubic feet) of natural gas over the term of the licence;

(d) A point of export at the outlet of the loading arm of the natural gas liquefaction terminal to be located at District Lot 99, eight kilometers west of Kitimat, British Columbia; and

(e) An expiration clause where, unless otherwise authorized by the Board, the licence will expire after 10 years if LNG exports have not commenced on or before that date,

(the “Export Licence”).

AltaGas DCLNG submitted that the quantity of gas it sought to export did not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada, as required by section 118 of the *NEB Act*.

AltaGas DCLNG submitted that the North American market was generally efficient, transparent, liquid, and capable of responding to changes in supply and demand through price. AltaGas DCLNG also submitted that the resource base in Western Canada was very large, such that there were sufficient reserves for domestic demand over the 20-year term, as well as surplus for additional growth for either excess domestic demand or other export project as well. AltaGas DCLNG provided evidence that horizontal drilling and fracturing technology have sharply increased natural gas, natural gas liquids and crude oil supplies in North America. AltaGas DCLNG submitted a demand sensitivity analysis considering a 20 percent increase in Canadian demand over the term of the Export Licence, and found that it would not change its overall conclusions of adequate supply for domestic markets.

The NEB agreed with AltaGas DCLNG, holding that the exports did not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada as required by section 118 of the *NEB Act*. The NEB also held that the estimates provided in the application were generally consistent with the NEB’s own monitoring effects.

The NEB therefore granted the Export Licence to AltaGas DCLNG as applied for.

NewTimes Energy Ltd. Application for a Licence to Export Liquefied Natural Gas Reasons for Decision (January 14, 2016)
Licence to Export – Liquefied Natural Gas

NewTimes Energy Ltd. (“NewTimes”) applied to the NEB pursuant to section 117 of the *National Energy Board Act* (“*NEB Act*”) for a licence to export natural gas in the form of liquefied natural gas (“LNG”) on the following terms and conditions:

(a) A term of 25 years starting on the issue date of first export;

(b) A maximum annual export quantity of 19.09 billion cubic metres (10^9m^3) of natural gas, subject to a 15 percent annual tolerance;

(c) A maximum term quantity of 458.16 10^9m^3 (or 16,173.60 billion cubic feet) of natural gas over the term of the licence;

(d) A point of export at the outlet of the loading arm of the natural gas liquefaction terminal to be located near Prince Rupert, British Columbia; and

(e) An expiration clause where, unless otherwise authorized by the Board, the Licence will expire after 10 years if LNG exports have not commenced on or before that date,

(the “Export Licence”).

NewTimes submitted that the quantity of gas it sought to export did not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada as required by section 118 of the *NEB Act*.

NewTimes submitted that the North American market was generally efficient, transparent, liquid, and capable of responding to changes in supply and demand through price. NewTimes submitted that it expected LNG exports from Canada would be limited, as there are no large buyers committed to purchasing long-term LNG from Canada. NewTimes also submitted a demand sensitivity analysis considering a 20 percent increase in Canadian demand over the term of the Export Licence, and found that it would not change its overall conclusions of adequate supply for domestic markets.

The NEB agreed with NewTimes, holding that the exports did not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada as required by section 118 of the *NEB Act*. The NEB also held that the estimates provided in the application were generally consistent with the NEB’s own monitoring effects.

NewTimes submitted that it would act as exporting agent for third parties, and as such requested relief from the monthly filing requirements of Section 12 of the *National Energy Board Act Part VI (Oil and Gas Regulations)* and Section 4 of the *National Energy Export and Import Reporting Regulations* (“*Reporting Regulations*”). NewTimes requested filing quarterly reports in lieu of monthly reports for its obligations under the *Reporting Regulations* as NewTimes submitted that monthly reports may prejudice its competitive position.

The NEB granted NewTimes' request for relief from Section 12 of the *National Energy Board Act Part VI (Oil and Gas Regulations*). The NEB also held that section 116 of the *NEB Act* does not require the holder of an export licence to be the owner of the natural gas, therefore the NEB found it unnecessary to include a term allowing NewTimes to act as agent for other parties. Therefore, the NEB held that, in acting in its capacity as agent, NewTimes was required to report export in accordance with the *Reporting Regulations*, and therefore denied NewTimes' request for quarterly reporting. The NEB addressed NewTimes' concern about exposing its competitive position, noting that the information supplied by an export licence holder is not necessarily the information that is published by the NEB in its market monitoring reports.

The NEB therefore granted the Export Licence to NewTimes consistent with the determinations set out in this decision.