ISSUE:
OCTOBER 2014
DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

*This monthly report summarizes energy decisions or resulting proceedings from applications before the Alberta Energy Regulator ("**AER**"), the Alberta Utilities Commission ("**AUC**") and the National Energy Board ("**NEB**"). For further information, please contact Rosa Twyman at Rosa.Twyman@RLChambers.ca or 403-930-7991 or Vincent Light at Vincent.Light@RLChambers.ca or 403-930-7994.*

IN THIS ISSUE:

ALBERTA ENERGY REGULATOR

Legacy Oil + Gas Inc. Application for Expansion of Turner Valley Unit No. 5 – Turner Valley Field (Decision 2014 ABAER 11)
Land Expansion

Legacy Oil + Gas Inc. ("Legacy") applied to add two tracts of land to Turner Valley Unit No. 5 (the "Unit"), pursuant to section 6 of the *Turner Valley Unit Operations Act* ("*TVUOA*"). The land is described as tracts 5Q and 5R, consisting of 4-7-019-02W5M and all of 12-019-3W5M, except 16-12-019-3W5M.

Although no statements of concern were received on the application to expand the Unit, the AER is required to hold a hearing on an application to expand a unit under section 6(1) of the *TVUOA*. Accordingly, as no objections were received, the AER opted to hold a written hearing.

The AER considered three main issues with respect to Legacy's application to expand the Unit:

(a) Whether the application is in accordance with the provisions of the relevant act;

(b) Whether the application would have adverse environmental, social, and economic effects; and

(c) Whether the application would have adverse impacts on landowners.

Legacy submitted that the expansion was necessary to allow the drilling of future injection wells to provide pressure support and voidage replacement on the southwestern portion of the field. The AER held that while its normal practice for an enhanced recovery scheme requires that a step-out well be drilled and supporting data show that the well is in the target pool, the geological information provided by Legacy was sufficient to determine that any future wells would be within the same pool.

Legacy also submitted that the expansion of the Unit would not affect any owner's share of the Unit production, as required by section 6(2) of the *TVUOA*. The AER, accordingly, held that the application was in accordance with the provisions of the *TVUOA*.

As the application by Legacy was only for the expansion of the Unit, and not to drill any wells (which would be the subject of separate applications), the AER held that the application would not have any environmental, social or economic impacts. Further, since no wells would be drilled, there would be no surface disturbances, and thus no adverse impacts on landowners.

The AER therefore ordered the expansion of the Unit to include tracts 5Q and 5R, and any subsequent amendments to Order No. TVU 5 necessary to reflect the AER's findings.

Grand Rapids Pipeline GP Ltd. Applications for the Grand Rapids Pipeline Project (Decision 2014 ABAER 12)
Pipeline Application – Constitutional Law Question – Pipelines Route Need

Grand Rapids Pipeline GP Ltd. ("Grand Rapids"), a company jointly owned by TransCanada PipeLines Limited and Phoenix Energy Holdings Limited, applied for approval to construct, operate and reclaim the Grand Rapids pipeline project, pursuant to the requirements of the *Pipeline Act*, the *Public Lands Act*, and the *Environmental Protection and Enhancement Act*.

The Grand Rapids pipeline project would consist of two main lines approximately 460 km in length with a maximum outside diameter of 508.0 mm (20 inches) and 914.0 mm (36 inches), respectively (the "Pipelines"). The Pipelines would transport diluted bitumen and diluents between the Grand Rapids Mackay terminal and a metering station located in Edmonton. The capacity of the 508.0 mm line would be 52,470 m^3/day (330,000 bpd), and the capacity of the 914.0 mm line would be 143,090 m^3/day (900,000 bpd).

Grand Rapids applied for four pump stations along the Pipelines, with the following pump ratings:

(a) Thornbury – 33,183 kW;

(b) Wandering River – 28,337 kW;

(c) Grassland – 38,031 kW; and

(d) Newbrook – 33,184 kW.

Grand Rapids applied for the following three terminals:

(a) MacKay, located near one end point of each of the Pipelines as a receipt point;

(b) Saleski, located approximately 70 km south of the MacKay terminal, and adjacent to the approved as of yet but unconstructed Laricina bulk storage facility; and

(c) Heartland, located near the other end point of each of the Pipelines as a delivery point.

Upon issuing a notice of hearing, the AER received 34 statements of concern, and granted participant status to 20 parties requesting to participate. Of these participants, only 12 registered to participate as intervenors in the hearing, including: MEG Energy Corp. ("MEG"), Fort Industrial Estates Ltd. ("Fort Industrial"), Laricina Energy Ltd.

("Laricina"), D&A Guenette Farms Ltd. ("Guenette") and the Athabasca Chipewyan First Nation ("ACFN").

The intervenors raised concerns with respect to the need for the Saleski terminal, the routing of the Pipelines and facility siting, construction and reclamation methods, emergency response procedures, and the effects of the project on land use, wildlife, wildlife habitat, aboriginal rights, and traditional land use.

Prior to the beginning of the hearing, ACFN applied for notice of questions of constitutional law ("NQCL"), asking whether:

(a) Section 21 of the *Responsible Energy Development Act* ("*REDA*") is constitutionally invalid? and

(b) The entire structure of the *REDA* is constitutionally invalid?

The panel held that any determination on the first question would be premature in the context of the application, and that it did not have the jurisdiction to inquire into the second question. ACFN withdrew from the hearing shortly afterward.

On matters related to the need for the project, Grand Rapids stated that the capacity for the line would be fully subscribed between Brion Energy's Dover steam assisted gravity drainage project, and anticipated incremental oil sands production, as the receipt point would be within 50 km of 15 different producers. None of the intervenors objected to the need for project, save for the Saleski terminal. Accordingly, the AER found that there was both a short-term and long-term need for the pipeline.

Laricina objected to the Saleski terminal on the basis that Grand Rapids did not have any agreements in place for the Saleski terminal, and there was no planned receipt or delivery infrastructure for the site. Laricina also raised concerns with respect to the location of the Saleski terminal, as it would be located approximately 200 meters from Laricina's own approved, but as of yet unconstructed tank farm. Laricina therefore requested that the application for the Saleski terminal be modified or denied to remove the storage tanks and reduce the plot plan accordingly.

The AER therefore considered the need for the facilities based on its obligation to promote the economic, orderly and efficient development of Alberta's oil and gas resources, as well as its proliferation policy. The AER noted the proliferation policy originated out of a need to reduce sour gas facilities. However, the AER held that the principles can be applied to all development, as the policy aligns with economic, orderly and efficient development. The AER did not find that the mere duplication of facilities was enough to warrant a denial of the application. The AER found that there was no short-term need for the Saleski terminal based on:

(a) The lack of committed shippers; and

(b) Grand Rapids' request for an extended approval in order to find commercial support.

Therefore, the AER denied the Saleski terminal portion of the application.

The AER approved Grand Rapids' proposed phased construction plan to build the smaller diameter pipe first. However, due to the fact that this approach was atypical, and would result in a larger right-of-way, the AER directed Grand Rapids to submit a detailed monitoring and response plan prior to February 28, 2015, along with its proposed mitigation measures.

Grand Rapids indicated that the majority of its proposed pipeline route follows existing linear disturbances, such as the North-East Pipeline Corridor and the Transportation and Utility Corridor. Grand Rapids submitted that this would minimize route length and minimize environmental impacts.

MEG objected to the routing of the pipeline, as it would interfere with MEG's plans to construct a rail terminal next to the Canadian National ("CN") rail line. MEG submitted that, since Grand Rapids' proposed route would be adjacent to the CN rail line, it would therefore require a number of crossings, thicker pipe, deeper depth of cover, and other mitigation measures. MEG also submitted that an approval of the Grand Rapids proposed right-of-way would require MEG to seek approval from Grand Rapids to develop the portions of its planned facility on the right-of-way.

The AER held that Grand Rapids' desire to use the existing right-of-way along the CN rail line was evidence that it was not prepared to assess alternative routes as proposed by MEG. Accordingly, the AER refused to permit any construction or incidental activities between LSD 16-6-056-20W4M and the Heartland terminal until such time as Grand Rapids conducts an analysis of at least one alternative pipeline route that avoids MEG's lands.

Fort Industrial objected to the routing of the pipeline over its lands, as it submitted the impact of the right-of-way over its industrial lands was incompatible, and would essentially sterilize them from future industrial use. Fort Industrial proposed an alternative route that would traverse farmland, which could be continuously harvested over the right-of-way.

Grand Rapids submitted that the route it proposed was the shortest, and that there was no short or medium term demand for industrial land held by Fort Industrial. Grand Rapids also submitted that the lands could still be used for industrial purposes in any event.

The AER held that it was not sufficient for Grand Rapids to rely on the fact that the proposed route was the shortest as a justification for the proposed route. The AER also determined that it was short-sighted for Grand Rapids to rely on short and medium term land use planning for a pipeline with such a long lifecycle. Therefore, since Grand Rapids did not supply any quantitative route comparisons with alternative pipeline routes, the AER refused to allow construction or incidental activities between NE 7-055-21W4M and SE 6-054-22W4M until Grand Rapids conducts an analysis of at least one alternative pipeline route that avoids the Fort Industrial lands.

Guenette Farms, located on S 34-054-22W4M, NW 27-054-22W4M and NE 28-054-22W4M (the "Guenette Lands"), submitted that although they were in support of the proposed Pipelines, they objected to the routing of the pipeline over their lands. Guenette Farms submitted that, since approximately 13 pipelines already cross one quarter section of their land, they had effectively done their "fair share" and were no longer willing to sacrifice land value for additional pipelines.

The AER reiterated its findings in respect of the Fort Industrial lands as applicable to the Guenette Lands, and refused to allow construction or incidental activities on the Guenette Lands until such time as Grand Rapids conducts an analysis of at least one alternative pipeline route that avoids the Guenette Lands.

In the result, the AER approved the applications, with a number of exceptions and conditions. The AER either denied, placed conditions on, or accepted the withdrawal of the following portions of the application:

(a) The AER denied the application with respect to the Saleski terminal, as Grand Rapids had not demonstrated a short-term need for the Saleski terminal;

(b) Grand Rapids withdrew its application to approve the Newbrook pump station;

(c) The AER refused to grant an application for crossings of the Athabasca River, as it understood that Grand Rapids would be submitting a new application on a revised route that would follow the existing Stony Mountain pipeline, resulting in less disturbance;

(d) The AER ordered Grand Rapids not to construct the pipeline along or crossing the following lands:

  (i) Immediately north of the Canadian National rail line;

  (ii) Across lands held by MEG on sections 26, 27, and 35 of Township 055-21W4M;

  (iii) Across lands held by Fort Industrial in the west half of Section 1-055-22W4M; and

  (iv) Across land held by Guenette in the south half of Section 34-054-22W4M, NW 27-054-22W4M, and NE 28-054-22W4M.

The AER also forbade Grand Rapids from undertaking any preliminary or incidental work along these lands until a route is approved.

The AER determined that the effects of the project on fish, wildlife, watercourse crossings, air emissions and air quality could be appropriately managed or mitigated through the measures proposed by Grand Rapids.

ALBERTA UTILITIES COMMISSION

ATCO Electric Ltd. 2012 Transmission Deferral Account and Annual Filing for Adjustment Balances (Decision 2014-283)
Deferral Account – Adjustment Balance – Prudency – Cost Overruns Addition to Rate Base

ATCO Electric Ltd. ("ATCO") applied for the disposal of its 2012 Transmission Deferral Account and Annual Filing for Adjustment Balances ("TDA") and to add approximately $583.5 million to its rate base. ATCO later adjusted this request to remove capital additions of approximately $25 million from the application.

Statements of Intent to Participate were received from the Consumers' Coalition of Alberta ("CCA"), EPCOR Distribution & Transmission Inc. ("EDTI"), the Industrial Power Consumers Association of Alberta ("IPCAA"), the Office of the Utilities Consumer Advocate ("UCA"), the Alberta Direct Connect Consumers Association ("ADC") and AltaLink Management Ltd. ("AltaLink"). ADC, the CCA and IPCAA joined to form the Ratepayer Group (the "RPG").

With respect to direct assigned transmission capital project expenditures, ATCO calculated a total net refund of approximately $24.5 million to the Alberta Electric System Operator ("AESO") based on its applied for additions to rate base in 2012 from over 20 projects.

Prudence Test

On matters related to the test applicable to a prudence analysis for investments by a transmission facility operator, the RPG challenged the current prudence test applied on the basis that the current presumption of prudence is:

(a) Counterproductive to a "culture of prudence" in investment decisions; and

(b) Creates an "information asymmetry" as the transmission facility operator, by being in possession of all of the evidence, is practically able to dictate the content of the proceeding.

The RPG therefore submitted that the AUC should apply the following set of 15 prudence principles to adjudicate the reasonableness and prudence of ATCO's application:

(a) Full disclosure or transparency;

(b) No withholding;

(c) No hindsight;

(d) Best interests of customers;

(e) Satisfactory Execution;

(f) Continuous monitoring;

(g) Timely Decisions;

(h) Cost diligence;

(i) Abandonment cost recovery;

(j) Risk reward;

(k) Contractor Accountability;

(l) Procurement Practices;

(m) Compliance;

(n) Greater disclosure accountability with construction work in progress in rate base; and

(o) Prudent management practices.

The UCA supported the use of the above principles as useful and non-exhaustive criteria for assessing the prudence of costs incurred by a utility.

With respect to the information asymmetry, the RPG proposed reversing the onus of establishing prudence, in accordance with the Supreme Court of Canada's judgment in *Snell v Farrell*, "where the subject matter of the allegation lies particularly within the knowledge of one party, that party may be required to prove it."

ATCO, by contrast, submitted that the AUC apply the concept of reasonableness as set out in the Supreme Court's decision in *Dunsmuir v New Brunswick* ("*Dunsmuir*").

The AUC declined to adopt the new test as proposed by the RPG, holding that the current test for prudence as set out in past decisions was a correct and concise expression of the legal assessment required for a prudence analysis. However, the AUC did note that the proposed list of principles set out by the RPG could be used as "an array of specific inquiries that may or may not inform the Commission's prudence evaluation in the instant case."

The AUC declined to apply the onus suggested by the RPG in *Snell v Farrell*, noting that the onus established in that case was attributable to the specific nature of a doctor-patient relationship and issues of medical malpractice, to address barriers faced by plaintiffs without specific knowledge of the allegation. The AUC considered that the information request process, when applied properly, affords the required opportunity for parties to correct any "information asymmetry".

The AUC also declined to adopt the reasonableness standard in *Dunsmuir* as it did not view the concept of reasonableness for judicial review as synonymous with reasonableness for the purpose of assessing the prudence of an investment decision. The AUC further held that to apply the *Dunsmuir* standard would also risk conflicting findings from previous AUC decisions, and would inappropriately narrow the relevant inquiries to questions of deference.

The AUC therefore held that the current test, in concert with section 121(4) of the *Electric Utilities Act* ("*EUA*") did not warrant any amendments or alterations.

Cost Variances

The UCA submitted concerns that overall ATCO experienced $234.5 million in cost overruns on 2012 capital expenditures (40 percent of the $583.5 million in capital costs ATCO sought to add to rate base). The UCA further submitted that if ATCO's proposals were reasonably accurate, then the AUC should consider the prudence of incurring these cost overruns.

ATCO submitted that the "baseline estimates" of a proposal to provide service is made at a far earlier stage than usual, and are not made with full knowledge of all facts and information, particularly in new project areas.

The AUC agreed with the UCA that the magnitude of the variance from initial estimates raised a general cause for concern, however the AUC stopped short of accepting the UCA's argument. The AUC noted that the purpose of comparing a proposal to provide service and a final cost is to identify areas of significant variance and to investigate the causes of these variances, including cost control by ATCO. The AUC also noted that, as the allowance for funds used during construction was subsequently removed from cost estimates in Decision 2011-134, the comparison of current actual costs to these estimates at the proposal stage would be unhelpful in context.

The AUC however, in delivering its decision on the filing requirements of the decision, did note its particular concern that the information provided in ATCO's original filing did not include a clear breakdown of the original cost estimates of approximately 20 projects it was seeking to add to rate base in 2012. As a result, to prevent this from recurring in the future, the AUC directed ATCO to match its proposal for service estimates to specific facilities it proposes to include in rate base for that year. ATCO was also directed to provide sufficient information to match projects to other associated decisions, such as Needs Identification Document ("NID")applications, subsequent decisions, specific permits, and other amendments.

Contingency Funds

ATCO had applied for contingency funds using ten percent of expenditure as a "rule of thumb". The AUC expressed concern with this approach as it was lacking in empirical rigour and did not compare well to alternative methods. The AUC held that the risk register approach to classifying financial risks was advantageous in that it would facilitate the removal of risk line items and their corresponding risk amounts when it becomes clear that the risk will not materialize. The AUC held that to apply a blanket ten percent would effectively shield some line items from a prudence review despite potential cost overruns. Therefore the AUC directed ATCO to implement contingency allowances in the future on a risk register based approach to determine the appropriate contingency allowance.

NE Loop Project

The AUC considered ATCO's NE Loop project approved by Decision 2011-520, of which the cost overruns were $87.1 million higher than the NID and proposal to provide service estimates. The original cost of the project was estimated at $237.4 million. The AUC therefore proposed to assess the prudence of ATCO's decisions with respect to the NE Loop project using the following factors:

(a) The AESO's mandate and oversight role in the execution of the NE Loop project;

(b) ISO Rule 502.2 and its various specification requirements for equipment;

(c) Project timing and schedule delays;

(d) Tendering of foundation contracts;

(e) Land access, geotechnical and foundation issues;

(f) Project and construction management processes;

(g) Accommodation costs; and

(h) Miscellaneous costs.

ATCO submitted that its costs were reasonable, as evidenced by the audit and oversight function of the AESO, its following of AESO directions, and the AESO's acknowledgment of forecast costs as reasonable. However, the RPG submitted that the AESO's oversight function does not operate as a prudence review, since the assessment is broad, designed for planning purposes, and does not involve the same level of detail. The UCA also submitted that ATCO's repeated insistence that it was bound by AESO direction was not evidence of prudent decision-making, as it had a duty to capture efficiencies, and not simply follow the AESO's direction.

The AUC held that the AESO does not assess the prudence of costs, and that ATCO's decisions are being reviewed, not the AESO's. However, due to the fact that the AESO had input into the decision making process to some degree, the AUC would consider the AESO's involvement as having some bearing on the prudence of ATCO's execution of the project, notably, with respect to the AESO's acknowledgment of cost increases, and its expectation of an April 1, 2012 in service date for the NE Loop project.

The AUC held that ATCO and the AESO's knowledge with respect to the required in service date of April 1, 2012 by Husky was gained after most of the key decisions with respect to costs had been made, and therefore the AUC held that ATCO had not acted unreasonably by proceeding to execute the project for an April 1, 2012 in service date.

In respect of whether the equipment specifications under ISO Rule 502.2 were reasonable, ATCO submitted that the use of RC-22 transmission towers was reasonable, due to the imminent implementation of ISO Rule 502.2, which had not occurred at the time the NID was approved. Rule 502.2 now requires the use of RC-22 transmission towers to meet the changes proposed for the long term. The RPG noted ATCO's failure to comply with other parts of ISO Rule 502.2, such as not completing a line optimization study, as evidence that compliance with ISO Rule 502.2 was not necessary. The RPG also noted that ISO Rule 502.2 expressly allowed for the application of existing specifications for already approved bulk transmission lines in lieu of the new specifications. Therefore the RPG submitted that the application of the new RC-22 transmission tower specification was not necessary.

The AUC held that at all relevant times, ATCO was given direction by the AESO to proceed with the NE Loop project. Section 35 of the *Electric Utilities Act* ("*EUA*") requires a transmission facility operator to comply with directions from the AESO to construct a facility, unless to do so would create a real and substantial risk with respect to damage to facilities, safety of employees or injury to the environment. Accordingly, the AUC gave significant weight to the direction from the AESO in assessing the prudence of ATCO's decisions. Accordingly, the use of RC-22 towers, and the application for steel lattice towers was reasonable, and the application of ISO Rule 502.2 by ATCO was appropriate.

The AUC noted that Husky's direct intervention in securing an earlier in service date which, it turns out, was not needed, significantly impacted the cost of the project. The AUC reiterated its finding in Decision 2014-242 that the AESO must draft provisions to allow costs associated with the advancement of system-related projects to be attributable to the end-use customer that fails to provide adequate notice of its needed in service date, as happened in this instance.

The AUC further determined that the land access, geotechnical studies and foundation issues could not have reasonably been anticipated by ATCO given its past experience, and the fact that some factors, such as extreme weather, were beyond its control. Therefore the AUC held that the additional expenses borne by ATCO were reasonable in this instance.

While the AUC found the remaining expenses, including project management costs, to be reasonable, the AUC held that ATCO had not discharged its burden under section 121(4) of the *EUA* to demonstrate legal fees claimed was just and reasonable for the NE Loop project.

The AUC noted that legal counsel was retained for primarily three broad functions: the development of a robust standard form contract; assessment and evaluation of bid compliance throughout the tendering process; and legal disputes. The AUC determined that ATCO's decision to retain legal counsel to assess and evaluate bids was essentially a decision to obtain additional assurance of the correctness of work its staff was already doing. Accordingly, while the AUC allowed the recovery of the remaining two expense categories, it disallowed the expenses for bid compliance. The AUC directed ATCO to revise its submission in its refiling.

<u>Accruals</u>

The RPG made submissions with respect to accruals included in the application, requesting that they be excluded from any addition to rate base, as accruals are not final costs, but simply estimates. The AUC accepted this core position from the RPG, as it noted that additions to rate base are final and not refundable. The AUC directed ATCO to remove approximately $4.48 million in accruals from its refiling.

<u>Remaining Projects</u>

The AUC approved amounts for the remaining projects that ATCO sought to add to rate base in full, with the exception of the following:

(a) Quigley 144-kV line and substation;

(b) Germain 144-kV line and substation;

(c) Livock 240-144kV substation;

(d) Green Stocking 925S substation; and

(e) Enbridge Leismer Point of Delivery Chard 658S.

The AUC determined that there were either unexplained variances between ATCO's cumulative monthly amounts and the requested amounts, or that customer contributions for these projects had not been finalized, and directed ATCO to explain any variances, and to state the final amount in its refiling.

The cost of the Kearl 240-kV transmission line purchased by ATCO from Imperial Oil Resources Ventures Limited ("IORVL"), along with due diligence, negotiation and environmental assessment costs, was approved by the AUC, less the allowance for funds used during construction, as

IORVL performed the construction and was not subject to regulatory oversight by the AUC in this respect.

Approved 2012 Addition

In the result, after adjusting for $7.6 million in accruals and trailing costs, and $8.9 of costs that the AUC directed ATCO to refile, the AUC approved an approximate total of $546.2 million to rate base for 2012. ATCO had requested the addition of $583.5 million to rate base for 2012.

All remaining amounts in the application were approved as filed. However, the AUC directed ATCO to refile its carrying costs in accordance with the revisions directed by the AUC.

The AUC directed to submit a filing reflecting its findings, on or before November 5, 2014.

EPCOR Distribution & Transmission Inc. 2014 Rider J Adjustment Application (Decision 2014-287)
Rider J Adjustment – Recover Over-refund

EPCOR Distribution & Transmission Inc. ("EDTI") applied for an adjustment through its Rider J to recover an over-refund to its customers totalling $2.6 million made in July 2014.

No other parties or stakeholders objected to, or provided a statement of interest to participate in the proceeding.

The AUC had previously approved EDTI's Rider J charge in Decision 2013-375, to be effective between January 1, 2014 and June 30, 2014. Due to problems in EDTI's billing system, the application of Rider J rates continued through July 2014 for non-direct connect rate classes. This resulted in an effective termination date of August 1, 2014, creating an excess refund of approximately $2.6 million to customers.

EDTI proposed to collect the over-refunded amounts during a two month period, effective November 1, 2014 to December 31, 2014, in combination with other Rider J true-up amounts previously approved in Decision 2014-245. EDTI submitted that the monthly change to rates for customers would not exceed 5.01 percent of the average monthly bill.

The AUC accepted that the billing was made in error and should not have been charged. The AUC also accepted that the rate impacts would not constitute a rate shock, as no rate class would experience a variance of greater than 10% of a total bill. Accordingly, the AUC approved the adjustment to Rider J from November 1, 2014 to December 31, 2014.

ATCO Gas and Pipelines Ltd. Rider D Application for Unaccounted for Gas (Decision 2014-290)
Unaccounted for Gas – Rider D

ATCO Gas and Pipelines Ltd. ("ATCO") applied to the AUC for approval of its unaccounted for gas ("UFG") rate rider D for 2014 and 2015. ATCO applied for this UFG rate riders to be effective from November 1, 2014 with an increase in the UFG percentage from 0.954 percent to 1.125 percent, to be recovered in kind from shippers on the ATCO system.

Previous AUC decisions required that ATCO submit the following information with any subsequent UFG applications:

(a) Explanations for seasonal UFG differences, measurement corrections and reasons for any UFG increases/decreases; and

(b) Information on practices and procedures employed to reduce UFG in future applications.

ATCO did not propose any changes to its methodology for calculating UFG rate rider D as between rate classes, but would calculate the charges based on aggregated north and south data.

ATCO noted that the variation in some monthly UFG figures was accounted for largely by monthly meter reads on consumer meters, and low flow on large meters during summer months below the operating range of the meters. Other sources for potential UFG were noted by ATCO as possibly arising from mixing of gas sources with different heat rates.

Upon review, the AUC held that the methodology and rate calculation for UFG rate rider D was accurate and consistent with prior approved methodologies, and approved it on that basis. The AUC also approved the UFG percentages as within the acceptable historical UFG percentages on a three year basis, but remained concerned with the overall variances in UFG amounts.

The AUC recognized that all gas distribution pipeline systems have UFG as an element inherent in the operation of the system, and that the percentage will fluctuate to some degree over time. Therefore, the AUC directed ATCO to continue to:

(a) Provide clear explanations of seasonal UFG differences, measurement corrections and reasons for UFG increases or decreases; and

(b) Provide information on practices and procedures it has employed to reduce UFG in future applications.

AltaGas Utilities Inc. 2014-2015 Unaccounted for Gas Rider E and Rider H (Decision 2014-291)
Unaccounted for Gas – Rider E & H

AltaGas Utilities Inc. ("AUI") applied for approval of annual adjustments to its unaccounted for gas ("UFG") rate riders E and H. AUI applied for these UFG rate riders to be effective from November 1, 2014 on a percentage basis as follows:

(a) An increase to UFG Rate Rider E from 1.28 percent to 1.31 percent; and

(b) An increase to UFG Rate Rider H from 1.30 percent to 1.33 percent.

AUI did not propose any changes to its methodology for calculating UFG rate riders E and H as between rate classes.

In its previous decisions respecting UFG levels, the AUC had directed AUI to provide the following explanations in subsequent applications:

(a) Monthly receipt and delivery volumes for the previous five years and the UFG percentage changes;

(b) Detailed explanations of seasonal UFG changes;

(c) Reasons for increases/decreases and what additional steps AUI took to reduce UFG in this application; and

(d) An explanation of capital and other projects initiated over the past five years and forecast projects designed to improve UFG data and reduce UFG amounts.

Upon review, the AUC held that the methodology and rate calculation for UFG rate riders E and H were accurate and consistent with prior approved methodologies, and approved them on that basis. The AUC also approved the UFG percentages as within the acceptable historical UFG percentages on a five year basis.

The AUC recognized that all gas distribution pipeline systems have UFG as an element inherent in the operation of the system, and that the percentage will fluctuate to some degree over time. However, the AUC also held that the UFG fluctuations and overall UFG percentages should decline over time, as AUI's initiatives are implemented to do so. Therefore, the AUC directed AUI to continue to:

(a) Quantify causes of UFG where possible, and provide reasons for any increase or decrease; and

(b) Provide updates to date, up to the current month for receipt and delivery volumes and UFG percentage losses or gains.

ENMAX Power Corporation 2013 Transmission Access Charge Deferral Account Reconciliation (Decision 2014-292)
Transmission Access Charge Deferral Account

ENMAX Power Corporation ("EPC") applied to the AUC for approval to reconcile its 2013 transmission access charge ("TAC") deferral account. Due to adjustments of the Alberta Electric System Operator's ("AESO") rates, EPC's TAC deferral account rider also required changes related to adjustments to the system access service rates in EPC's distribution tariff.

EPC applied for approximately $3.503 million in adjustments. EPC had originally applied for an aggregate amount of $3.495 million, however, this was adjusted upward due to changes in carrying cost calculations for the proposed effective date of November 1, 2014. EPC proposed to collect this amount from November 1, 2014 to January 31, 2015. This figure was arrived at as the net amount of the following four figures:

(a) The 2013 TAC rider true-up collection of $10.315 million;

(b) The TAC deferral account true-up refund of $6.988 million;

(c) The balancing pool true-up collection of $0.0069 million; and

(d) The carrying cost collection of $0.106 million, according to AUC Rule 023.

EPC proposed to collect the amounts on an energy-based, $/kWh basis. EPC submitted that the rate impacts would be below 10 percent for all rate classes.

The AUC approved this collection methodology as reasonable, and determined that it did not constitute rate shock for consumers.

The AUC's prior Decision 2012-304 set a standardized methodology for quarterly transmission riders for Alberta distribution facility owners, including EPC.

The Consumers' Coalition of Alberta ("CCA") took issue with EPC's methodology of calculating the reconciliation amount. CCA submitted that the AESO operating reserve charges and Rider C amounts in volume variance calculations for the TAC should be excluded from the reconciliation amount. The CCA also pointed to AUC Decision 2013-377, which determined that the TAC deferral account methodology should not be modified to flow through volume variances before the end of EPC's formula based ratemaking term.

EPC submitted that the changes did not contradict the AUC's prior findings in Decision 2013-377, noting that the method used for calculating the TAC deferral account balance was approved in that decision. In addition, EPC noted the AUC's ruling that no changes to the methodology were required before the expiry of the formula based ratemaking term.

The AUC determined that EPC's calculation and methodology in determining the TAC deferral account balance was consistent with past applications. The AUC also held that the inclusion of the AESO operating reserve and Rider C amounts was also consistent with past applications.

With respect to volume variance issues raised by the CCA, the AUC noted that such issues are being considered in EPC's 2014 Phase I Distribution Tarff application, and that proceeding would be the appropriate forum to address any changes to EPC's deferral account methodology. Accordingly, the AUC rejected the CCA's proposals to change the treatment of AESO operating reserve charges and Rider C amounts in the TAC deferral account methodology.

The AUC authorized EPC to collect $3.503 million through its TAC rider, to be effective from November 1, 2014 to January 31, 2015.

Balancing Pool Preferential Sharing of Records between the Balancing Pool, Capital Power Generation Services Inc., Capital Power L.P. and each of ANC Power Inc. and TransCanada Energy Ltd. Part C (Decision 2014-293)
Balancing Pool – Preferential Sharing of Records

This decision is part C of a series of decisions arising from an application by the Balancing Pool pursuant to section 3 of the *Fair, Efficient and Open Competition Regulation*. The application sought an order for the sharing of records not available to the public between the Balancing Pool, Capital Power Generation Services Inc., Capital Power L.P. and each of ANC Power Inc. ("ANC") and TransCanada Energy Ltd. ("TCE") related to strip contract sales from a power purchase arrangement from the Genessee #1 and Genessee #2 generation units.

In this portion of the application, the Balancing Pool notified the AUC that ANC and TCE were the successful bidders of its strip contract process for 100 MW each from the Genessee #1 and Genessee #2 units.

As the AUC found that the Balancing Pool had already met the requirements for the preferential sharing of records in Decision 2014-231, the AUC did not need to make any findings in this respect, and granted the application on the same terms and conditions as set out in Decision 2014-231 for ANC and TCE.

ATCO Electric Ltd. 2014 Interim Rates (Decision 2014-295)
Interim Rates

ATCO Electric Ltd. ("ATCO") applied to the AUC for approval of its 2014 Interim Rates, to be effective August 1, 2014, including a request to include 100 percent of the 2013 and 2014 capital trackers applied for in Proceeding 3218, in the amount of $24.2 million. Proceeding 3218 is still under consideration by the AUC.

In considering the merits of the interim rate application, the AUC applied the test as established in Decision 2005-099, which sets out the various factors employed to evaluate an interim rate application. These factors can be grouped into two categories as follows:

(a) Factors that affect the quantum of, and need for the requested rate increase, including:

   (i) A probable and material revenue deficiency exists or will exist;

   (ii) All or some portion of contentious items are excluded;

   (iii) The increase is required to avoid financial hardship, or to preserve the financial integrity of the applicant; and

   (iv) Whether safe utility operations can continue without the rate adjustment; and

(b) Following a determination on the quantum and need, the AUC will assess general public interest factors to see if a rate increase is justified by looking at whether:

   (i) Interim rates promote rate stability and ease rate shock;

   (ii) Interim adjustments help maintain intergenerational equity;

   (iii) Interim rate increases can be avoided through the use of carrying costs;

   (iv) Interim rates provide appropriate price signals; and

   (v) Interim rate riders can be applied "across-the-board".

ATCO provided submissions that its application met this test, citing its business case for continued funding, and that any continued mismatch in revenues collected and capital funding would contribute to regulatory lag, creating potential for intergenerational inequity.

The Utilities Consumer Advocate rejected ATCO's assertions respecting the need for the rate increase based on financial integrity, citing the ATCO's exceedance of the authorized

8.75 percent return on equity placeholder despite only receiving 60 percent of 2013 capital tracker revenue during 2013.

The Consumers' Coalition of Alberta ("CCA") also suggested the use of negative capital trackers, similar to its suggestion made in evidence leading up to Decision 2013-435. The AUC noted that the evidence referred to by the CCA was rejected, and was struck from the record of that proceeding as being out of scope. Accordingly, the AUC declined to accept the CCA's submission, as the interim rate application was not a suitable forum for re-submitting evidence, and the interim rate application was also not a review and variance of Decision 2013-435.

The AUC declined to include 100 percent of the 2013 and 2014 capital trackers applied for in Proceeding 3218, citing unresolved issues in that proceeding. The AUC therefore elected to approve a placeholder amount equal to 90 percent of the capital trackers applied for in Proceeding 3218, as the amounts were considered material.

The AUC also noted that ATCO had consented to potentially including its approved refund to customers in the amount of $13.781 million (as approved in Decision 2014-169) in the interim rate application to help minimize rate fluctuations and rate shock concerns. Accordingly, the AUC determined that it would be in the interest of rate stability to collect the net amount of the capital tracker amounts and the proposed customer refund in November and December of 2014, as no customer would experience an increase greater than six percent in any period.

Therefore, the AUC approved ATCO's 2014 interim rates to include 90 percent of the capital tracker amounts requested, offset by the proposed refund amounts, and collected during November and December of 2014.

ATCO Gas and Pipelines Ltd. 2014 Interim Rates (Decision 2014-296)
Interim Rates

ATCO Gas and Pipelines Ltd. ("ATCO") applied to the AUC for approval of its 2014 interim distribution rates, to be effective August 1, 2014, including 100 percent of the revenue associated with the 2013 and 2014 capital trackers in Proceeding 3267, which is still ongoing before the AUC. The total capital tracker amount proposed in the interim rate application is $20.6 million.

In considering the merits of the interim rate application, the AUC applied the test as established in Decision 2005-099, which sets out the various factors employed to evaluate an interim rate application. The factors are listed in the above decision (ATCO Electric Ltd. 2014 Interim Rates (Decision 2014-295).

ATCO submitted that it met the test as set out above, noting specifically that over 80 percent of the applied for amounts have previously been reviewed by the AUC in Decision 2013-435, where the AUC agreed with the need and scope of the relevant programs.

The Utilities Consumer Advocate ("UCA"), by contrast, argued that ATCO had failed to demonstrate financial need for the interim rate increase, pointing to ATCO's exceedance of its authorized placeholder of 8.75 percent return on equity in 2013, despite receiving only 60 percent of 2013 capital tracker revenue during that period.

The AUC declined to include 100 percent of the 2013 and 2014 capital trackers applied for in Proceeding 3267, citing unresolved issues in that proceeding. The AUC therefore elected to approve a placeholder amount equal to 90 percent of the capital trackers applied for in Proceeding 3267, as the amounts were considered material.

The AUC also noted that ATCO had consented to potentially including its approved refund to customers in the amount of $25.547 million (as approved in Decision 2014-169) in the interim rate application to help minimize rate fluctuations and rate shock concerns. The AUC held that this was consistent with the UCA's position that known rate reductions should be included in interim rates. Accordingly, the AUC determined that it would be in the interest of rate stability to collect the net amount of the capital tracker amounts and the proposed customer refund beginning in November 2014. The AUC held that rates would remain stable, pointing to small reductions in November and December 2014, followed by two to three percent increases beginning in 2015.

Therefore, the AUC approved ATCO's 2014 interim rates to include 90 percent of the capital tracker amounts requested, offset by the proposed refund amounts, to be collected beginning in November 2014.

ATCO Electric Ltd. 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances (Decision 2014-297)
Distribution Deferral Account – Annual Filing

ATCO Electric Ltd. ("ATCO") requested approval to dispose of its 2012 distribution deferral accounts and annual filing for adjustment balances. In total, ATCO requested a total collection of approximately $34.393 million.

ATCO included carrying costs within its application calculated on an assumed dispensation of the application between January 1, 2014 and December 31, 2014.

<u>$400,000 Retirement Costs for assets lost or destroyed by fires near Slave Lake, Alberta</u>

The AUC determined this issue by relying on the *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)* ("*Stores Block*") decision setting out principles of corporate and property law as applicable in the utility context. The AUC held that customers do not acquire an interest in the property in rate base by virtue of being customers, and that the risk and reward associated with the asset must ultimately follow the property owner. Upon finding that no express wording within the *Electric Utilities Act* would serve to displace these clearly enunciated principles of corporate and property law, the AUC held that the fundamental nature of allocating risk and reward to the owner of the assets continued to apply in this context. Therefore, any gain or loss on the assets in the Slave Lake fire would therefore accrue to ATCO in the context of its application, as in any other asset retirement application.

<u>Typical or Extraordinary Event</u>

The relevant inquiry in determining whether an event is typical or non-typical, was whether the event in question had been contemplated or anticipated by a prior depreciation study.

On a review of the history of losses provided by ATCO, the AUC determined as a fact that the characteristic of the Slave Lake fires were sufficiently different from the characteristics of other fires and natural disaster events upon which the AUC based ATCO's Reserve for Injuries and Damages account ("RID") assessments in Decision 2007-071. The Slave Lake fires could not reasonably have been anticipated or contemplated in the determination of the parameters used in the previous ATCO depreciation study.

Therefore, the destroyed assets from the Slave Lake fires is an extraordinary retirement. The remaining $400,000 net book value of the destroyed assets are for the account of ATCO shareholders.

<u>Replacement Assets</u>

The AUC accepted the UCA's intergenerational equity concerns given that the $23.2 million in costs to replace these extraordinary retirements should be capitalized and amortized, because new facility construction has an extended life. Because the RID policies do not address intergenerational equity, the RID was not intended to recover costs in magnitude of the present application, as the historical averages were nearly all under $1 million on an annual basis.

Accordingly, as the AUC previously held that the retirements should be on account of shareholders, it held that the RID mechanism was inapplicable, and therefore treated the replacement costs as a capital addition.

<u>Camp Cost Associated with Replacement</u>

ATCO had also applied for the collection of approximately $4.47 million in associated camp costs with the replacement of the assets. The UCA opposed the inclusion on the basis that ATCO failed to inquire into lower cost alternatives, and that the 15% markup included in subcontracted services was commercially unreasonable for an affiliate transaction.

The AUC held that the expenses were generally reasonably and prudently incurred, given the devastation arising from the Slave Lake fires, and lack of alternative accommodation in the aftermath of the fires. However, the AUC directed ATCO to remove $400,000 from the camp costs. The 15% markup was unreasonable because ATCO had failed to inquire about the markup, despite its past commercial dealings with its affiliates.

The AUC found that the balance of applied for expenses were reasonable, however, given the disallowances, the AUC directed ATCO to submit a compliance filing to reflect the AUC's findings. These directions include:

(a) An explanation of how ATCO intends to refund amounts already collected under its Y factor rate adjustment for the $23.2 million related to the Slave Lake fires disallowed by the AUC;

(b) Deducting $400,000 from the requested camp costs, including any additional amounts already accounted for under allowances for funds used during construction;

(c) Addressing whether adjustments to rate base are necessary for the inclusion of the costs of replacement assets; and

(d) A rationale for selecting an effective date to remove the destroyed assets from rate base.

ATCO was directed to file its compliance filing no later than November 30, 2014.

Various AUC Facility Applications
Facility Application

The AUC approved the following facility applications upon finding that:

- The public consultation complies with *AUC Rule 007*;
- The noise impact assessment summary will comply with *AUC Rule 012*;
- Technical, siting and environmental aspects of the facilities comply with *AUC Rule 007*; and
- Considering the social, economic and environmental impacts, the project is in the public interest.

Decision	Party	Application
2014-294	AltaLink Management Ltd.	Beamer 233S Substation Telecommunications Upgrade
2014-299	Suncor Energy Operating Inc.; Fort Hills Energy Corporation	Fort Hills Industrial System Transmission Lines and Fort Hills Industrial System Connection

NATIONAL ENERGY BOARD

Energy East Pipeline Ltd. Application for the Energy East Project
Application – Energy East Project

On October 30, 2014 Energy East Pipeline Ltd. ("Energy East") applied to the NEB to construct and operate the Energy East Project. The Energy East Project will consist of approximately 1,500 km of new nominal pipe size ("NPS") 42 pipeline, in:

(a) Alberta (284 km);

(b) Eastern Ontario (104 km);

(c) Quebec (693 km); and

(d) New Brunswick (407 km).

Energy East also proposed to make use of existing facilities, notably the conversion of approximately 3,000 km of TransCanada PipeLines Limited's existing NPS 42 natural gas pipeline, in:

(a) Saskatchewan (614 km);

(b) Manitoba (465 km); and

(c) Northern Ontario (1,922 km).

Among other facilities, the Energy East Project is proposed to include:

(a) 71 pump stations;

(b) Four tank terminals at Hardisty, Alberta, Moosomin, Saskatchewan, Cacouna, Québec, and Saint John, New Brunswick; and

(c) Two marine terminals at Cacouna, Québec and Saint John, New Brunswick.

Update to Filing Requirements for Offshore Drilling in the Canadian Arctic
Offshore Drilling Filing Requirements

The NEB has updated its *Filing Requirements for Offshore Drilling in the Canadian Arctic* document to provide greater clarity regarding information requirements for incident management and emergency response procedures under sections 4.18, 4.19, and 5.12.

There are currently no applications before the NEB with respect to offshore drilling in the Beaufort Sea, however, the NEB encourages regulated companies to review the new filing requirements.

Auditor General's Report: 2014 Fall Report of the Commissioner of the Environment and Sustainable Development
Environmental and Sustainable Development Efforts – Audit Report

The Office of the Auditor General, through the Commissioner of the Environment and Sustainable Development released its 2014 Fall Report to Parliament on a broad range of topics related to the federal government's environmental and sustainable development efforts.

The Auditor General found the NEB had successfully implemented the *Canadian Environmental Assessment Act*, 2012 ("*CEAA*") in many respects, however, the remainder of the report found several deficiencies with respect to the broader framework of implementing environmental and sustainable development targets. Notably, the Auditor General found deficiencies with respect to environmental monitoring of the oil sands, and mitigating the effects of climate change.

On assessing the reduction of emissions to mitigate climate change, the report analyzed the following four areas:

- Putting measures in place to reduce greenhouse gas emissions;
- Assessing the success of the measures;
- Working with the provinces and territories; and
- Developing plans to achieve the 2020 Copenhagen Accord target of a 17-percent reduction in emissions below 2005 levels for Canada's economy as a whole.

The report noted that "federal departments have made unsatisfactory progress in each of the four areas examined" since the Auditor General's last audit on the same subject, and that several timelines and targets have not been met, delayed, or will be missed.

With respect to the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring, the Auditor General found that most of Environment Canada's commitments and projects planned in 2013-2014 were implemented according to relevant timelines and budgets. However, the Auditor General noted that Environment Canada's future role beyond 2015 was not well defined, and that further efforts in engaging stakeholders and incorporating traditional ecological knowledge (especially from First Nations and Métis) was needed.

The Auditor General found that the Canadian Environmental Assessment Agency had poorly defined criteria for identifying which project would undergo an environmental assessment under the *CEAA*, whereas it noted that projects under the purview of the NEB automatically require environmental assessments.

On matters of public participation required under the *CEAA*, the Auditor General found that while the NEB employs an intelligible participation framework, it found that the guidance for participation was based on the *National Energy Board Act* (the "*NEB Act*") and did not refer to the *CEAA*, which applies a lower threshold for participation. The Auditor General recommended that the NEB update its participation guidance to match the *CEAA* requirements.

The *CEAA* requires that the NEB must hear from those directly affected by a project, or persons with relevant information and expertise. The *NEB Act* stipulates that the NEB may hear from those directly affected by a project, or persons with relevant information and expertise.

The NEB agreed to update its participation framework to reflect this recommendation by March of 2015.

The Auditor General also found that public participation guidance was not in place for offshore drilling projects under the *Canada Oil and Gas Operations Act* ("*COGOA*"). The NEB's current practice is to apply the same test used for pipeline and power line projects under the *NEB Act*. The Auditor General recommended that the public participation guidance be updated for offshore drilling projects under the *COGOA* in a manner consistent with the *CEAA*.

The NEB agreed to update its participation framework to reflect this recommendation by July of 2015.

The Auditor General further recommended that the NEB update its guidance for assessing cumulative effects to include projects under the *COGOA*. The NEB agreed to update its cumulative effects guidance by July of 2015.

Enbridge Pipelines Inc. Line 9B Reversal and Line 9 Capacity Expansion Project Order XO-E101-003-2014, Condition 16 Filing – Line 9 Intelligent Valve Placement Methodology and Results
CSA Z662-11 Requirements – Condition of Order

Enbridge Pipelines Inc. ("Enbridge") throughout June and August of 2014, filed documents with the NEB pursuant to Condition 16 of the Order XO-E101-003-2014, which required Enbridge to "demonstrate that the new Line 9 valves system meets or exceeds the requirements of CSA Z662-11 clause 4.4 Valve location and spacing, with particular reference to clause 4.4.8, note (2)."

The relevant portions of the CSA Z662-11 standard are as follows:

- Valves shall be installed on both sides of major water crossings; and
- A major water crossing means a water crossing that in the event of an uncontrolled product release poses a significant risk to the public or the environment.

The NEB held that Enbridge's criteria for determining what is a major water crossing was not adequate, as it relied heavily on areas noted as highly populated areas as a criteria.

The NEB ordered Enbridge to develop a new criteria to identify major water crossings, which must consider high consequence areas, including highly populated areas, other populated areas, drinking water resources, environmentally sensitive areas and commercially navigable waterways.

Upon a review, the NEB held that it was not persuaded that Enbridge met the requirements of Condition 16, and in any event could not properly assess the remaining portions of Condition 16 without further submissions. Accordingly, the NEB directed Enbridge to file a revised submission for Condition 16 at least 90 days prior to applying for a final leave to open of the Line 9 Reversal and Capacity Expansion Project.

NOVA Gas Transmission Ltd. Application for the Integration Asset Transfer Project (Decision GH-002-2014)
Asset Transfer

NOVA Gas Transmission Ltd. ("NGTL") applied to the NEB for approval of its Integration Asset Transfer Project (the "Project"). NGTL requested leave to execute a sale of assets from NGTL to ATCO Gas and Pipelines Ltd. (the "ATCO"), (the "NGTL Transferred Assets") and a purchase of assets from ATCO by NGTL (the "ATCO Transferred Assets").

Specifically, NGTL requested:

(a) Leave to sell the NGTL Transferred Assets and purchase the ATCO Transferred Assets in accordance with their asset swap agreement, as either four separate closings, or one single closing, if a single certificate is issued by the NEB;

(b) Certificates under section 52 of the *National Energy Board Act* ("*NEB Act*") to allow for the continued operation of the assets within the NEB's jurisdiction;

(c) An order under section 47 of the *NEB Act* for leave to open the ATCO Transferred Assets;

(d) Approval for adjustments to rate base under section 59 of the *NEB Act* by the difference in the aggregate net book value of the NGTL

Transferred Assets and related Monetary Adjustments; and

(e) Approval to create a Non-Monetary Adjustment Deferral Account.

The Transferred Assets

The NGTL Transferred Assets consisted of:

(a) 120 meter stations (31 for delivery and 89 for receipt); and

(b) 1,418 km of pipeline.

The ATCO Transferred Assets consisted of:

(a) One compressor station (Noel Lake);

(b) 30 meter stations (11 for delivery and 19 for receipt); and

(c) 1,249 km of pipeline.

The assets to be transferred between NGTL and ATCO were generally described to be assets owned by one company within the "footprint" area of the other. Put simply, ATCO's "footprint" was primarily noted to be the Calgary-Edmonton corridor, and the NGTL "footprint" would comprise the balance of federally regulated pipelines within Alberta. Each "footprint" primarily contained assets belonging to the party to whom the "footprint" was designated, with a small number of exceptions. The application proposed to swap ownership of any assets within the other party's "footprint".

Stoney Nakoda Nations' Objection

The Stoney Nakoda Nations ("Stoney Nakoda") objected to the transfers asserting:

(a) Inadequate consultation by NGTL;

(b) That pipelines on federal lands must fall under federal jurisdiction; and

(c) Effects to their traditional lands.

The NEB dismissed the objections in its reasons. No new construction was slated to occur, and the jurisdictional matter is currently in dispute before the courts. Consultation by NGTL was adequate, and the jurisdictional objections were outside the scope of the application. Similarly, as there was no new construction proposed, the NEB held that no new or increased contributions to cumulative effects were likely to occur from the asset transfers.

Assets Value and Transfer Costs

No shippers or intervenors raised any issues with respect to the valuation of assets and costs of the transfer.

Monetary and Non-Monetary Adjustments

No shippers or intervenors raised any issues with respect to the Monetary Adjustments or Non-Monetary Adjustment Deferral Account.

Abandonment Costs

With respect to the abandonment cost estimates, the NEB held that the difference in costs was not material, however it still expected adherence to Decision MH-001-2013. In particular, adherence to section 6.2 in respect of management systems and providing revisions to funding for future abandonment costs.

NEB Findings

The NEB found the valuation, and adjustments to account for differences in the valuations, to be reasonable. Accordingly, the NEB held that no tariff amendments would be required to implement the asset transfers. The NEB also approved the monetary and non-monetary adjustments proposed by NGTL pursuant to section 59 of the *NEB Act*, and approved NGTL's proposed Non-Monetary Adjustment Deferral Account as applied for.

The NEB was satisfied that the ATCO Transferred Assets met the *National Energy Board Onshore Pipeline Regulations* ("*OPR*") requirements and that the facilities were fit for designed service. Therefore, the NEB granted leave to NGTL to open the facilities under section 47 of the *NEB Act*. However, citing safety and operational concerns, the NEB required that NGTL incorporate the ATCO Transferred Assets into its existing Security Management Program, and provide confirmation of the same in writing to the NEB.

The NEB approved both the purchase and sale pursuant to section 74(1)(a) and 74(1)(b) of the *NEB Act*, however, the approval was conditional upon receiving clearance under Part IX of the *Competition Act*, as NGTL and ATCO's previous approval under that Act had since expired.

The NEB also varied the existing Certificate of Public Convenience and Necessity GC-113 with a single amending order under sections 20 and 21(2) of the *NEB Act* to reflect the transfer of the assets subject to Decision GH-002-2014. The orders made by the NEB come into effect if the Governor in Council directs the NEB, under section 54 of the *NEB Act,* to issue the Certificate.

Trans Mountain Pipeline ULC Trans Mountain notice of motion and Notice of Constitutional Questions, dated September 26, 2014 Ruling No. 40
NEB Ruling – Order against Municipality

Trans Mountain Pipeline ULC ("Trans Mountain"), as part of its Trans Mountain Expansion Project (the "Project"), under an NEB ruling, needed to perform testing, surveys and other examinations for fixing the site of the Project. The City of Burnaby ("Burnaby") submitted that this testing violated the *Burnaby Parks Regulation Bylaw*, 1979. Burnaby contended that such violations barred Trans Mountain from accessing lands and issued to Trans Mountain:

(a) Orders to Cease Bylaw Contraventions; and

(b) Bylaw notices for damage and destruction to trees or plants in violation of the *Burnaby Parks Regulation Bylaw*, 1979.

As was reported in the September, 2014 issue of this newsletter, Trans Mountain had previously filed a motion requesting an order granting temporary access to the Burnaby lands. Because Trans Mountain's motion raised a constitutional question, and neither party had filed a Notice of Constitutional Question, the NEB dismissed the motion.

Trans Mountain re-applied to the NEB requesting an order pursuant to sections 12, 13 and 73(a) of the *National Energy Board Act* ("*NEB Act*") to:

- Direct the City of Burnaby (Burnaby) to comply with paragraph 73(a) of the *NEB Act* permitting temporary access to lands by Trans Mountain for the purposes of geotechnical surveys, examinations, and associated activity necessary for fixing the site of the pipeline; and
- Forbid Burnaby from denying or obstructing Trans Mountain or its representatives and agents in gaining temporary access to their lands for the purpose of making surveys, examinations, or other necessary arrangements for fixing the site of the pipeline.

In this ruling, the NEB held that it did have authority to consider constitutional questions in respect of its own jurisdiction pursuant to sections 11, 12 and 13 of the *NEB Act*. As a result, the NEB made four main findings:

(a) The NEB has the necessary jurisdiction to find that specific Burnaby bylaws are inoperative to the extent they impair the operation of section 73(a) of the *NEB Act* in preventing Trans Mountain from accessing the lands, and prevents the NEB from fulfilling its statutory duties;

(b) Doctrines of federal paramountcy and interjurisdictional immunity applies, and renders the Burnaby bylaws inapplicable with respect to section 73(a) of the *NEB Act*;

(c) The NEB is empowered to make an order against Burnaby, pursuant to section 13(b) of the *NEB Act*; and

(d) The facts in this circumstance necessitate granting an order against Burnaby.

Accordingly, the NEB issued Order MO-122-2014 to Burnaby forbidding it from interfering or obstructing Trans Mountain from exercising its powers under section 73(a) of the *NEB Act*. The order expires upon completion of the work required for surveys and examinations by Trans Mountain, or on July 30, 2015, whichever occurs first.

NEB Inspection Officer Orders KAR-001-2014 and KAR-002-2014
Unauthorized Excavation Activities

On October 6, 2014 the NEB was advised by Montreal Pipelines Ltd./Portland Pipeline Corporation ("Montreal Pipeline") that a landowner(s) had undertaken two instances of unauthorized excavation activities within 30 metres of one of Montreal Pipeline's facilities located in Quebec, and did not cease the excavation when requested to do so.

Upon investigating the information, the NEB Inspection Officer determined that the excavation activity was unauthorized and in contravention of Section 49(2)(a) of the *Pipeline Crossing Regulations*, Part I. Therefore, pursuant to the Inspection Officer's powers under section 51.1 and 51.1(2) of the *National Energy Board Act*, the landowner in question was ordered to:

(a) Take measures, including ceasing all excavation within 30 metres of Montreal Pipeline's pipe, for guarding the safety or security of the public or employees, or protecting property or the environment; and

(b) Suspend work until the hazard had been remedied to the satisfaction of the Inspection Officer, or until otherwise ordered by the NEB.

FEDERAL COURT OF APPEAL

City of Vancouver v National Energy Board and Trans Mountain Pipeline ULC; Docket 14-A-55: Application for Leave to Appeal National Energy Board Decision No. 25 in OH-001-2014
Leave to Appeal - Denied with Costs

The City of Vancouver applied to the Federal Court of Appeal for leave to appeal the NEB's Ruling No. 25 in Hearing Order OH-001-2014 on the grounds that:

(a) The NEB derogated its statutory responsibility under the *National Energy Board Act* and the *Canadian Environmental Assessment Act*, 2012 ("*CEAA*") by refusing to consider the upstream and downstream effects from oil sand production relative to the Trans Mountain Expansion Project; and

(b) The NEB erred in law or jurisdiction in doing so.

The Federal Court of Appeal denied leave with costs.

In Ruling No. 25 in Hearing Order OH-001-2014 the NEB held that the Trans Mountain Expansion Project did not include any upstream production, nor was it dependent on any particular development. The NEB noted that oil sands production and their effects were more effectively regulated by the jurisdiction closest to the use of the resource. The NEB held that an assessment of the downstream effects were not required under the *CEAA*. Accordingly, the NEB had denied the original motion by the City of Vancouver.

Forest Ethics Advocacy Association v National Energy Board, 2014 FCA 245
Judicial Review - Dismissed

Forest Ethics Advocacy Association ("Forest Ethics") applied to the Federal Court of Appeal (the "Court") for judicial review of three interlocutory decisions of the NEB associated with the Line 9B Reversal and Line 9 Capacity Expansion Project under Hearing Order OH-002-2013.

The Court denied the applications for Charter relief and held the NEB's decisions were reasonable. The appeals were dismissed.

In the subject interlocutory decisions, the NEB held as irrelevant:

(a) Environmental and socio-economic effects associated with upstream activities, including oil sands development in Alberta; and

(b) The downstream use of oil transported by pipeline.

Forest Ethics Contended:

(a) In light of the NEB's duty to consider specific issues under section 52(2) of the *National Energy Board Act* (the "*NEB Act*"), the NEB was required to consider the larger environmental effects of the project, including upstream and downstream effects; and

(b) Both the NEB's removal of these issues, and section 55.2 of the *NEB Act* itself, violates the parties' rights to freedom of expression under section 2(b) of the *Canadian Charter of Rights and Freedoms*. Accordingly, Forest Ethics also sought a declaration that section 55.2 of the *NEB Act*, which is used to determine who may participate in a hearing before the NEB, was of no force or effect under subsection 52(1) of the *Constitution Act*, 1982.

Another applicant, Ms. Sinclair, applied for similar relief, arguing that the NEB failed to take into account her freedom of expression and religious beliefs. In doing so, she was unreasonably denied the ability to participate in the hearing, despite having information and expertise relevant to the issues under consideration by the NEB.

The NEB and Enbridge Pipelines Inc. submitted that the appellants had not raised the Charter issues before the NEB, and were raising these issues for the first time before the Court. Accordingly, the Court turned its assessment to two issues:

(a) Whether the applications were barred from seeking Charter relief on the application for failure to raise it before the NEB; and

(b) Whether the NEB's interlocutory decisions should be quashed for unreasonableness.

Stratas J.A., writing for the Court, found that the NEB's decisions did not impose any obligations on Forest Ethics, nor prejudicially affect Forest Ethics' rights in any sense. The Court also rejected Forest Ethics' claim to public interest standing, holding that Forest Ethics had fallen "well short" of meeting that test.

Forest Ethics was asking to review an administrative decision it had nothing to do with. The record did not disclose any real stake or genuine interest from Forest Ethics in relation to freedom of expression issues before the NEB. Allowing such a request, the Court reasoned, would allow Forest Ethics (or other unaffected parties) to pre-empt legitimate judicial review applications by those with a vital interest in the matter. Therefore, Forest Ethics was barred from seeking Charter relief as it lacked standing before the Court. Under subsection 18.1(1) of the *Federal Courts Act,* only those who are “directly affected” can apply for judicial review.

Stratas J.A. held that in order to seek Charter relief in the Court, the appellants must have raised it first before the administrative decision maker. Stratas J.A. declined to apply *Alberta (Information and Privacy Commissioner) v Alberta Teacher's Association,* (2011 SCC 61)(“*Alberta v ATA*”), because it did not apply to consideration of constitutional decisions. Even if it did, the Court would not exercise its discretion to hear the issues on judicial review. Under *Alberta v* ATA, discretion will not be exercised where the issue could have been raised before the decision maker of first instance, but was not. The Appellants also could have challenged the NEB's interlocutory decisions in a request for a review and variance under section 21(1) of the *NEB Act*, but chose not to.

Barring the applicants from seeking Charter relief on a judicial review for matters not raised before the NEB, respects the fundamental division between an administrative decision maker and the reviewing court. The intention of Parliament, in conferring powers under the *NEB Act*, assigns the responsibility to determine merits of factual and legal submissions to the NEB, not to the Court.

The applications for Charter relief were denied.

The second issue of the unreasonableness of the NEB's interlocutory decisions were reviewed on a standard of reasonableness. The NEB interpreted its home statute, and was therefore entitled to deference.

The applicant, Ms. Sinclair, argued that by failing to consider the larger environmental issues, the NEB's decisions were automatically invalidated. The Court strongly rejected this approach to a reasonableness review, noting that the applicant's submission “smacks of the old nominate category of review known as ‘failing to take into account a relevant consideration’”. *Alberta v ATA* rejected such an approach, in favour of the modern approach of applying degrees of deference to a decision maker's interpretation of a statute, including which factors it considers relevant and irrelevant.

Accordingly, after reviewing the NEB's findings in respect of the scope of its duties under section 52 of the *NEB Act*, and its broader responsibilities under Part III of the *NEB Act*, the Court held that the decision was reasonable. The decision reached an outcome within a range of acceptability and defensibility in respect of the facts and law.

Denying participation to Ms. Sinclair was reasonable. The NEB properly applied the test under section 55.2 of the *NEB Act* and its references to fairness signalled a sensitivity to the interest of each applicant by assessing whether the applicant's need to make submissions were outweighed by the need for such submissions to be relevant and useful under section 55.2 of the *NEB Act*. The NEB's review of Ms. Sinclair's application was also reasonable and defensible in respect of the facts and law, insofar as it characterized her interests as only of a general nature, noting she did not reside in the vicinity of the project.

The Court dismissed the appeals with costs.