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REGULATORY
LAW CHAMBERS

# ENERGY REGULATORY REPORT

***Regulatory Law Chambers*** *is a Calgary-based energy boutique law firm dedicated to excellence in energy regulatory matters. 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 ("AER"), the Alberta Utilities Commission ("AUC"), the National Energy Board ("NEB") and 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](mailto:Rosa.Twyman@RLChambers.ca) or Vincent Light at [Vincent.Light@RLChambers.ca](mailto:Vincent.Light@RLChambers.ca).*

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**<u>IN THIS ISSUE:</u>**

## ALBERTA ENERGY REGULATOR

***Revised Directive 058 – Addendum: Oilfield Waste Management Facility Approvals – Notification and Amendment Procedures Released (AER Bulletin 2015-01)***
***Bulletin - Directive – Oilfield Waste Management***

Effective January 14, 2015, Directive 058 – Addendum: Oilfield Waste Management Facility Approvals – Notification and Amendment Procedures Released ("Directive 058") will replace the previous addendum released on December 23, 2008.

Notably, section 3.2.6 of Directive 058 was amended to dispense with the 25 percent limit on out-of-province oilfield wastes received at an AER-approved oilfield waste management facility.

Current oilfield waste management facility approval holders must file an amendment application with the AER to remove any such volume limitations.

The remainder of Directive 058 remains unchanged from the previous iteration.

***Consent Submissions for Public Lands Disposition Applications (AER Bulletin 2015-02)***
***Bulletin – Consent Submission – Public Lands Act Applications***

This bulletin clarifies the administrative completeness requirements for *Public Lands Act* applications related to consents provided via e-mail to Electronic Disposition System (EDS) users.

Consents from all other existing disposition holders within the application area must be obtained prior to conducting any activity on the lands in question. The list of disposition holders from whom consent must be obtained has now expanded to include:

(a) Timber dispositions: forest management agreement area (FMA), deciduous timber licence (DTL), coniferous timber licence (CTL), deciduous timber permit (DTP), and coniferous timber permit (CTP);

(b) Agricultural dispositions: grazing lease (GRL), grazing permit (GRP), and forest grazing licence (FGL); and

(c) Sample plots dispositions: industrial sample plot (ISP), and disposition reservation (DRS).

Applications not including the required consent information will be rejected by the AER as incomplete.

## ALBERTA UTILITIES COMMISSION

***New Decision Numbering Format***
***Decision Numbering Format Change***

The AUC has changed its decision numbering system for 2015 to include the decision's associated Proceeding ID number. Until 2014, AUC decisions were numbered sequentially by year (i.e. 2014-001, 2014-002, etc.). Current AUC decisions are now numbered according to the following formula:

> *Decision [Proceeding ID]-D[Decision Number within the Proceeding]-[Year of Decision]*

***AUC Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments (AUC Bulletin 2015-01)***
***Bulletin – Rule 007***

Based on previous consultations with stakeholders, the AUC announced approval of changes to Rule 007*: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* ("*Rule 007*") effective January 16, 2015.

The materials related to the *Rule 007* consultation are posted on the AUC's website at Rule 007 - Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments.

***Consultation on AUC Rule 027: Specified Penalties for Contravention of Reliability Standards (AUC Bulletin 2015-02)***
***Bulletin – Rule 027***

Up to January 29, 2015, the AUC invited comments from market participants and interested parties regarding possible amendments to AUC Rule 027: *Specified Penalties for Contravention of Reliability Standards*.

Since the last amendment to the rule, the AUC has approved 14 new reliability standards, and removed one. The proposed amendments to the rule related to the inclusion of the new standards, as well as minor clerical revisions.

The proposed revisions can be found by clicking on the following link.

***ATCO Utilities (ATCO Gas, ATCO Pipelines, and ATCO Electric Ltd.) 2013 Pension Application (Decision 2954-D01-2015)***
***Pensions Costs – AUC Jurisdiction – Cost-of-Living Adjustment***

ATCO Electric Ltd. ("ATCO Electric"), ATCO Gas, and ATCO Pipelines, (collectively, the "ATCO Utilities"), applied to the AUC for approval of the 2013 pension costs. In accordance with the Decision 2011-391, the ATCO Utilities filed:

(a) An updated actuarial valuation for pension funding as of December 31, 2012; and

(b) Supporting evidence to recover the full pension costs identified in the actuarial valuation report.

The ATCO Utilities are participants in the "Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies" (the "Pension Plan"), administered by Canadian Utilities Limited ("Canadian Utilities").

The ATCO Utilities requested 2013 pension costs of:

(a) $7.1 million for ATCO Electric – Transmission; and

(b) $5.4 million for ATCO Pipelines.

The ATCO Utilities noted that the current service costs of pensions are as follows:

(a) $3.9 million for ATCO Electric – Transmission; and

(b) $3.0 million for ATCO Pipelines.

In the previous AUC Decision 2011-391, the AUC directed ATCO to limit its cost-of-living adjustment ("COLA") to 50 percent of the consumer price index ("CPI") to a cap of three percent ("50 percent COLA"). The impact of limiting the COLA to the 50 percent COLA resulted in a revenue requirement reduction of $4.9 million for the ATCO Utilities. The ATCO Utilities requested cost recovery using a COLA based on 100 percent of the CPI to a cap of three percent ("100 percent COLA") as calculated in the actuarial valuation effective January 1, 2013.

The AUC received four statements of intent to participate, one of which was from the Office of the Utilities Consumer Advocate (the "UCA").

Pension Legislation

The AUC noted that pensions are governed by provincial pension legislation, notably the *Employment Pension Plans Act* ("*EPPA*"). The *EPPA*, among other things, requires a pension plan administrator to require that plan funding be adequate to protect the rights and obligations of members covered by the plan. The AUC also noted that COLAs are considered to be ancillary benefits under the pension plan legislation and regulations.

Pension Plan

The Pension Plan consists of two components operating under a single plan: a defined benefit component ("DB Plan") and a defined contribution plan ("DC Plan"). The DC Plan was created in 1997, and the DB Plan has been closed to new ATCO Utilities employees since that time.

AUC's Jurisdiction

ATCO Utilities and the UCA each argued different positions with respect to the scope of the AUC's jurisdiction in assessing pension costs. ATCO Utilities suggested that the AUC had a much more limited scope of jurisdiction in regard to pension costs, and should not consider the resultant rate impacts of including such costs if they are prudent. The UCA argued that the AUC had a much broader jurisdictional power, including ensuring that overall compensation costs are prudent, and that the components of such compensation are both necessary and reasonable.

The AUC held that the *Gas Utilities Act* and the *Electric Utilities Act* provide the AUC with the authority to set just and reasonable rates. This broad and general power included the authority to assess management decisions. The AUC further held that the pension legislation itself may be instructive as to the parameters, procedures and requirements of a pension plan, but do not extend to whether such costs should be approved in a rate-setting context. The AUC found that ATCO Utilities would still bear the onus of proving that such costs to be recovered were reasonable.

Past Actions of the Pension Administrator

The AUC considered whether past actions by the pension administrator were relevant to assessing the applied for 2013 pension costs. ATCO Utilities submitted that the administration of its pension plan has been prudent and reasonable throughout the plan's history, noting its past actions to close the DB Plan provision to new entrants in 1997, and its various cost-containment measures since that time which have in turn benefitted ratepayers. The UCA submitted that past actions were irrelevant to the current proceeding, noting that a utility must demonstrate on an ongoing basis that its costs are prudently incurred and that resulting rates are just and reasonable.

The AUC determined that its findings would be based on the evidence filed on the record, and to the extent that such information relates to 2013 pension costs, or affect the pension plan going forward.

50 percent COLA vs. 100 percent COLA

ATCO Utilities argued that the AUC should consider the applicable COLA provisions of the DB Plan not in isolation, but in the context of overall compensation consistent with prior AUC decisions on similar matters. ATCO Utilities took the position that the 50 percent COLA, deprived ATCO Utilities of any opportunity to recover its prudently incurred costs, resulting in overall compensation falling below the median of other comparable utilities.

The UCA argued that, while the AUC does ensure that overall compensation, as well as the individual components that make up the overall compensation, are reasonable and necessary, the UCA took issue with ATCO Utilities' characterization of what were considered comparable utilities. The UCA also asserted that the change from the 100 percent COLA to the 50 percent COLA would only affect approximately \$0.077 per \$1.00 of additional contributions to improving the competitive position of the overall compensation of the ATCO Utilities.

The AUC agreed with the UCA's approach to compensation, looking at both the overall compensation and the individual components as reasonable and necessary. The AUC held that applying the 100 percent COLA versus the 50 percent COLA would result in incremental special payment expenses of approximately \$3.5 million and \$12.2 million. The AUC held that this would have a negligible impact on ATCO Utilities as compared to its peer competitor group, as the impacts between 100 percent COLA and 50 percent COLA would see ATCO Utilities remain within +/- 10 percent of the 50$^{th}$ percentile of its peer competitor group, regardless of which COLA percentage is applied.

The AUC therefore reasoned that an incremental expenditure of approximately \$15 million should not be recovered from utility customers, as the ATCO Utilities evidence demonstrated that the ATCO Utilities were market competitive when compared to their peer competitor group.

Further, the AUC held that:

(a) There were no explicit provisions in the pension plan text that prescribe a clear mechanical application of a COLA without any discretion on the part of the plan administrator;

(b) The pension plan does not clearly define how the CPI and previous adjustments are taken into consideration when setting the COLA for the year; and

(c) The pension plan text does not link the unfunded liability or financial position of the pension plan to the COLA provisions.

Therefore, the AUC found that the plan administrator was exercising discretion in the application of the annual COLA, and not simply following a mechanical exercise. The AUC noted the previous management decisions of the plan administrator as having a resulting impact on the forecast pension costs for which recovery is sought through ATCO Utilities' rates. However, the AUC held that there has not been a material change in circumstances or changes to the provisions of the pension plan to warrant an increase in the COLA to the 100 percent COLA. The AUC held that such an increase would be unreasonable in the circumstances, and that an application of the 50 percent COLA was reasonable in setting just and reasonable rates.

The UCA submitted that ATCO Utilities paid its 2012 DB Plan pension costs to retirees using the 100 percent COLA, despite the 50 percent COLA established by the AUC in Decision 2011-391. The AUC agreed with the UCA's submission, and held that the $996,000 paid to retirees in 2012 above the approved 50 percent COLA from ATCO Utilities' regulated entities' should not be recovered through rates. The AUC therefore directed ATCO Utilities to reduce its pensions costs to reflect the 50 percent COLA, and remove any accruing or compounding impact of the 100 percent COLA amounts from their revenue requirements.

AUC Ruling and Directions

The AUC approved the application of the 50 percent COLA as a reasonable COLA for regulatory purposes while the pension plan is in a deficit position. This would reduce service costs and the elimination of going concern special payments for both regulated and non-regulated participating companies in the pension plan.

The AUC further directed ATCO Utilities to identify the impact of the above findings as it applies to each of the ATCO Utilities, and to clearly identify the breakdown between current service costs and special payment costs, and further breaking down those items into capital versus operating and maintenance portions.

The AUC ordered the ATCO Utilities to file a compliance filing consistent with the findings of this decision by March 16, 2015.

***Milner Power Inc. Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology; ATCO Power Ltd. Complaint regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology – Phase 2 Module A (Decision 790-D02-2015)***

***ISO Rule – Complaint – Line Losses – AUC Authority***

Milner Power Inc. ("Milner") first filed its complaint with the AUC predecessor, the Alberta Energy and Utilities Board (the "AEUB"), on August 17, 2005 in respect of the Independent System Operator ("ISO" or "AESO") Rule 9.2: *Transmission Loss Factors* and Appendix 7: *Transmission Loss Factor Methodology and Assumptions* (collectively, the "*Line Loss Rule*"), implemented on January 1, 2006. Milner's initial complaint was dismissed by the AEUB, and that decision was later vacated by the Alberta Court of Appeal ("ABCA"), and remitted to the AUC for a rehearing.

In the time between the initial AEUB decision, and the Court of Appeal's determination remitting the decision to the AUC, the Line Loss Rule, the *Transmission Regulation* ("*T-Reg*") and the 2003 version of the *Electric Utilities Act* (the "*EUA*") in force at that time had all been updated, amended or refiled in some form. On June 11, 2012, Milner submitted a second complaint, on a without prejudice basis, in respect of the re-filed Line Loss Rule. ATCO Power Ltd. ("ATCO") also submitted a complaint on the same date.

The AUC initially held in Decision 2012-104 that the Line Loss Rule did not comply with the relevant provisions of the *T-Reg* and the 2003 version of the *EUA* in force at that time, and found that the Line Loss Rule was unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory, and inconsistent with and in contravention of the 2003 *EUA* and the relevant portions of the *T-Reg*. The AUC later confirmed these principal findings in a review and variance hearing, resulting in Decision 2014-110. These findings and decisions comprise Phase 1 of Proceeding No. 790.

The AUC determined that Phase 2 of Proceeding 790 would be split into three modules, the first of which is addressed by this decision. The AUC considered the following issues in this decision:

(a) Whether the Line Loss Rule, as it was from January 1, 2006 to the present, is a tariff, a rate, a charge, or something else. Whether a line loss factor produced by the Line Loss Rule is a tariff, a rate, a charge or something else. The legal significance of interpreting the line loss rule and/or the line loss factor as such;

(b) Whether or not Milner's 2005 complaint continued post-2008 and, if so, for how long;

(c) Compliance of the line loss rule, as it was from January 1, 2009 to the present, with applicable legislation and regulations; and

(d) For each of the periods from January 1, 2006 to December 31, 2008; January 1, 2009 to June 11, 2012; and June 12, 2012 forward, the AUC's jurisdiction to:

   (i) Change or replace an ISO rule that was in effect;

   (ii) Change the charges and credits for transmission line losses in an ISO tariff that was in effect; and

   (iii) Order any form of financial compensation including to whom and from whom such compensation might be paid.

Line Loss Rule as a Rate, Charge, Tariff or Something Else

The AUC looked to the statutory regime under the *EUA* and the *T-Reg* to determine the nature of the Line Loss Rule and its resulting loss factors as a rate, charge, tariff, or something else. The AUC noted that the ISO must "manage and recover the costs of transmission line losses" pursuant to section 17(e) of the *EUA*, and may include those costs either in the ISO tariff, or through charging ISO fees under section 30(4) of the *EUA*. The AUC found that the AESO has consistently recovered transmission line losses through the ISO tariff.

Milner 2005 Complaint Continue Post-2008

In respect of the status of Milner's complaint submitted in 2005, the AUC disagreed with the assertions of TransCanada Energy Ltd. ("TCE"), AltaGas Ltd. ("AltaGas"), Capital Power Corporation ("CPC") and TransAlta Corporation ("TransAlta") that the amendments to the Line Loss Rule resulted in the Milner complaint coming to an end.

The AUC held that the Line Loss Rule has continued in all relevant respects since it was put into effect January 1, 2006, as it continues to employ a marginal loss factor divided-by-two methodology ("MLF/2 Methodology"). The AUC found that neither the MLF/2 Methodology nor any other part of the Line Loss Rule was changed. With respect to the amendments to the *T-Reg*, the AUC held that such changes resulted only in a renumbering of the relevant sections, and not a substantive change.

In dealing with the continuing nature of the Milner complaint, the AUC also held that the Milner complaint would meet the statutory requirements for relief under the amended *EUA*. The AUC noted that no party made submissions on the compliance of the Line Loss Rule under this standard, and that the continuing nature of both the Line Loss Rule and the relevant sections of the *T-Reg* resulted in the Line Loss Rule not complying with the current statutory regime. As a result, the AUC held that a rule that contravenes an Act cannot be in the public interest, thereby satisfying the current requirement of demonstrating that the Line Loss Rule was not in the public interest under section 20.4(1).

Statutory Regime

The AUC found that the statutory regime governing ISO rules resulted in a scheme in which ISO rules are filed and become effective without any express regulatory approval, but are reviewed on a complaint basis. The AUC found that a similar regime exists in dealing with the ISO tariff under section 30 of the *EUA*, insofar as many of the rates or charges approved under the ISO's tariff are not reviewable by the regulator, except on a complaint. The AUC referred to the effect of the rulemaking provisions in the *EUA* as a "negative disallowance scheme". A "negative disallowance scheme" was described by the Supreme Court of Canada in *Bell Canada v Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 SCR 1722 ("*Bell Canada*") as "schemes which grant utility companies the right to fix tolls as they wish but also grant users the right to complain before an administrative agency which has the power to vary those tolls if it finds that they are not "just and reasonable"".

The AESO argued that the ISO tariff is a positive approval scheme, and thereby precluded a remedy through the tariff, given the AUC's positive approval in prior years. The AUC disagreed with this assessment, noting that the AUC effectively has no avenue through which it can test the justness and reasonableness of the line loss charges before approving them in the ISO tariff, except through a complaint against the Line Loss Rule itself. The AUC held that where rates to be approved in the ISO tariff are determined through an ISO rule, there is no "positive approval scheme".

Retroactive Rate Making and AUC Authority

As many parties made submissions on the AUC's authority with respect to retroactive ratemaking, the AUC undertook a review of the jurisprudence to determine whether its powers include the ability to grant tariff based relief from an unlawful ISO rule. All the parties agreed that, if the AUC posses the authority to retrospectively alter the unlawful rates, that authority must be found either in the statute itself, or in the common law interpreting such statutes.

The AUC noted a recent judgment of the ABCA, *Calgary (City) v Alberta (Energy and Utilities Board),* 2010 ABCA 132 for the proposition that retroactive or retrospective ratemaking is generally impermissible. However, the AUC found five exceptions to this prohibition on retroactive ratemaking in the case law:

(a) Adjustments to interim rates (*Re Coseka Resources Ltd. and Saratoga Process Co.*, 1981 ABCA 180);

(b) The use of deferral accounts to deal with differences between forecast and actual costs and revenues (*Bell Canada v Bell Aliant Regional Communications*), [2009] 2 SCR 764;

(c) Changes to rates as a result of the operation of a negative disallowance scheme (*Bell Canada*);

(d) Changes to rates where affected parties knew or ought to have known that rates were subject to change (i.e. the “knowledge exception”) (*ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission*), 2014 ABCA 397); and

(e) Replacing rates in a tariff that has been determined to be a nullity.

The AUC found that the operation of ISO rules, insofar as they affect the ISO tariff, were a negative disallowance scheme, in which the statutory scheme presumes that rates are just and reasonable from the outset. This presumption can be rebutted through a successful complaint or challenge to determine whether they are unlawful. In such a scheme, the AUC held that the regulatory agency must be taken to have the authority to revise rates with retroactive effect, at least to the date the complaint was made, subject to any statutory restrictions. The AUC supported this finding by noting the perverse incentives available to the parties making or supporting the rates by creating a regulatory delay if only prospective relief were available.

Since the AUC determined the existence of a negative disallowance scheme, it held that once Milner made its complaint, then all affected parties are taken to know two things:

(a) That the object of the complaint may change; and

(b) That if the complaint is upheld, the object of the complaint may change with retrospective effect to the date that the complaint was first made.

The AUC held that the imputed knowledge above is not disavowed by virtue of the complexity of the issues raised, the uncertainty of relief available, or the date from which such relief might be granted, and to whom such relief is available. The AUC also held that such knowledge is not dislodged by the number of regulatory or judicial proceedings required to arrive at such a finding, or the total length of time required to reach such a finding.

After review of the jurisprudence, the AUC set out four key findings on retroactive and retrospective ratemaking:

(a) Prohibitions on retroactive or retrospective ratemaking do not apply when parties knew or ought to have known that rates may be subject to change;

(b) In some cases, this knowledge may flow from the nature of the proceeding, such as for interim rates, deferral accounts or complaints against rates or rules subject to a negative disallowance scheme;

(c) Negative disallowance schemes share five main attributes:

(i) Rates or rules come into effect without prior review or approval;

(ii) Rates or rules are presumed to be just and reasonable until challenged by a written complaint;

(iii) Once a complaint is launched, the justness and reasonableness of the rate or rule remains in question until a final determination is made;

(iv) Pending such a final determination, parties remain on notice that the rate or rule remains subject to change; and

(v) If a rate or rule is determined to be unlawful, it may be changed with retroactive or retrospective effect to the date the complaint was first filed; and

(d) Policy concerns respecting prohibitions against retroactive or retrospective ratemaking are much diminished when parties know that rates may change. Such knowledge eliminates incentives for parties that have benefitted from unjust and unreasonable rates or rules to act opportunistically to the detriment of parties that would otherwise be unjustly harmed by the rate or rule.

<u>AUC Findings</u>

Accordingly, the AUC made the following findings in respect of the Line Loss Rule:

(a) The non-compliant provisions of the 2005 Line Loss Rule remain in effect today, and have remained in effect, and continue to be non-compliant with the *EUA* and the *T-Reg* uninterrupted since January 1, 2006;

(b) Milner’s complaint has continued and continues uninterrupted since August 17, 2005;

(c) The complaints against the Line Loss Rule satisfy the statutory requirements for the AUC to grant relief from January 1, 2009 forward, under either version of the *EUA*;

(d) The complaint in respect of the Line Loss Rule is to complain about the line loss charge components of the ISO tariff, and therefore those components of the ISO tariff are similarly unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory, and inconsistent with and in contravention of the *EUA* and the relevant portions of the *T-Reg*, since 2006;

(e) Any remedy the AUC may grant through a tariff-based remedy does not constitute retroactive ratemaking; and

(f) The AUC may grant a tariff based remedy or relief under the 2003 *EUA*.

The AUC noted that the relief and remedies to be granted in accordance with the above findings are to be determined in modules B and C of Phase 2 of Proceeding 790.

***EPCOR Energy Alberta GP Inc. 2015 Interim Regulated Rate Tariff (Decision 3461-D01-2015)***
***Regulated Rate Tariff – Revenue Deficiency***

EPCOR Energy Alberta GP Inc. ("EEA") applied for an interim regulated rate tariff ("RRT") to be effective January 1, 2015.

EEA submitted that the continuation of the interim 2014 RRT rates into 2015 would result in an accumulated forecast revenue deficiency of approximately $8.69 million by June 2015, amounting to 19 percent of EEA's 2015 forecast RRT non-energy revenue requirement of $45.19 million. This revenue deficiency was later revised in reply argument by EEA to 14.6 percent.

EEA proposed to collect 75 percent of the forecast revenue deficiency between the 2014 interim and 2015 forecast RRT rates over a five-month period, beginning on February 1, 2015.

The Utilities Consumer Advocate ("UCA") argued against the proposed interim rates, taking the position that EEA had not satisfied the quantum and need factors established in Decision 2005-099. In particular, the UCA argued that the financial hardship was overstated by EEA, and that the UCA's calculation of forecast revenue deficiency of $3.3 million would not cause EEA any financial hardship.

The AUC held that the UCA's calculations were incorrect, that the shortfall of 14.6 percent for the first six months of 2015 was material, and that further revenue deficiencies were probable. The AUC also noted that EEA had removed potentially contentious items from the calculation of its interim rates, supporting the quantum and need factors.

Therefore, the AUC held that an interim rate increase was necessary, since the revenue deficiency would have some financial impact on EEA, and that reducing these impacts may reduce potential intergenerational inequity and rate shock to consumers.

In noting EEA's request to recover 75 percent of the revenue deficiency, the AUC also noted its past practice of only approving the recovery of 50 percent of forecast revenue deficiency. The AUC held that the difference in the amounts to be collected over the six month period, whether for 75 or 50 percent of the revenue deficiency, would be relatively small. Accordingly, the AUC approved 50 percent of the applied for rate increase.

The AUC ordered EEA to file an interim price schedule, consistent with the findings in this decision by January 27, 2015.

***2013 PBR Capital Tracker True-up and 2014-2015 PBR Capital Tracker Forecast (Decision 3100-D01-2015)***
***Capital Tracker – PBR – K Factor – Revenue Requirement***

EPCOR Distribution & Transmission Inc. ("EDTI") requested approval for:

(a) Certain capital projects for capital tracker treatment in 2014 and 2015; and

(b) The associated revenue requirement for the capital tracker projects to be included in the K Factor component of the performance based regulation ("PBR") rate formula, which was approved by the AUC in Decision 2012-237.

The PBR formula applies for a five year term effective January 1, 2013 for EDTI. The PBR adjusts rates annually by means of an indexing mechanism, tracking the rate of inflation (I), less an offset for productivity improvements (X). This mechanism is known as the I-X mechanism. However, as utilities may not be able to recover all costs using an I-X mechanism, the PBR formula allows for three adjustment types:

(a) Adjustments for necessary capital expenditures in a year ("K Factor");

(b) Adjustments for flow through costs ("Y Factor"); and

(c) Adjustments to account for "material exogenous events for which the company has no other cost recovery or refund mechanism within the PBR plan" ("Z Factor").

In order for a "capital tracker" project to qualify for K Factor treatment, the utility would have to satisfy the following three-part test:

(a) The project must be outside of the normal course of the company's ongoing operations;

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

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

In order to qualify as "outside the normal course of on-going operations", the AUC noted that the increase in associated revenue provided by the PBR formula, must be insufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the capital tracker program or project in question. This test is therefore considered by the AUC as more accounting oriented than engineering oriented, although such applications must generally be supported by an engineering study and business case to assess the reasonableness of the request.

In order to qualify as being required by a third party under the second criterion, a growth related project must demonstrate that customer contributions and incremental revenues are insufficient to offset the revenue requirements associated with a project for a given PBR year.

The materiality threshold in the third criterion requires that each project must individually affect the revenue requirement by four basis points. On an aggregate level, all proposed capital trackers must have a total impact on revenue requirement of 40 basis points.

EDTI applied for approval of actual costs for its 2013 capital tracker projects, including:

(a) 14 projects which were previously approved in Decision 2013-435, with an aggregate variance of $0.63 million; and

(b) 3 projects which were not previously approved for capital tracker treatment with an aggregate cost of $0.57 million.

EDTI also applied for approval of its 2014-2015 forecast capital tracker projects, including:

(a) The continuation of 13 projects which were previously approved for capital tracker treatment in Decision 2013-435, with an aggregate cost of $9.54 million in 2014 and $16.41 million in 2015; and

(b) 10 projects which were not previously approved for capital tracker treatment, with an aggregate cost of $1.22 million in 2014, and $3.70 million in 2015.

<u>Project Grouping</u>

The Consumers' Coalition of Alberta ("CCA") argued that EDTI had grouped its projects in such a manner as to keep any projects for which the accounting tests are negative, outside of, or separate from, those that would require a K Factor amount. The CCA argued that, by grouping projects in such a way, EDTI was attempting to increase its return on equity. The CCA therefore requested that the AUC implement a "retrospective mechanism" to review the circumstances of expenditure deferral and strategic shifting of capital tracker projects.

EDTI submitted that the numbers provided by the CCA in support of its argument were unrealistic, had little value for the AUC, and constituted new evidence. EDTI did not support the use of a retrospective mechanism of any kind. EDTI also submitted that it had grouped its applied for projects consistent with past AUC directions.

The AUC held that any grouping of projects for the sole purpose of minimizing or maximizing capital tracker revenue would be contrary to the PBR model. The AUC noted that grouping projects in such a manner would likely be apparent on its face, as such groupings would be generally inconsistent with past accounting practices and regulatory reporting prior to the commencement of the PBR period.

The AUC noted that EDTI proposed some 60 capital project categories, raising prospects that such categories are overly refined, and that some categories contain the same asset types. However, the AUC also noted that EDTI used the same capital project categories from previous applications. The AUC held that EDTI had not manipulated its groupings, and therefore would not order any re-grouping of capital tracker projects. The AUC further held that any revisions to EDTI's capital tracker groupings would best be addressed in a review of its next PBR plan. The AUC approved EDTI's project groupings as reasonable.

The AUC rejected CCA's proposed retrospective mechanism, as most of the information sought was already available for scrutiny. The AUC further rejected the retrospective mechanism on the grounds that it would, in effect, require the AUC to examine and verify the entirety of a company's capital forecasts.

<u>2013 Project Deferrals</u>

EDTI applied for deferral treatment of:

(a) $12.21 million of capital tracker costs previously approved for expenditure in 2013, to be applied in 2014; and

(b) $6.54 million of capital tracker costs previously approved for expenditure in 2014, to be applied in 2015.

EDTI noted that the deferral of such work was precipitated mainly by the significant uncertainty arising from its previous capital tracker application, and the potential capital funding shortfalls.

The CCA expressed concerns about EDTI's rationale for deferrals, noting that customers experienced approximately 6,900 hours of service interruptions due to the deferred work not being completed. The Office of the Utilities Consumer Advocate ("UCA") submitted that substantial capital funding shortfalls, and regulatory uncertainty are not acceptable business reasons for deferring work required to ensure service reliability or safety.

The AUC agreed with the UCA's stance on project deferrals, noting that the AUC's approval is not required for a utility to undertake projects required to maintain service reliability and safety at adequate levels. However, the AUC also noted that 2013 was a year of transition for several utilities, in moving from a cost-of-service model to PBR. Therefore, the AUC held that it would consider the prudence of these expenditures at the time of EDTI's 2014 and 2015 capital tracker true-up applications, including any additional net costs that could have been avoided had the projects proceeded as planned.

<u>Project assessments</u>

EDTI provided a business case together with an engineering study for each of its programs and projects, consistent with the AUC's previous directions in Decision 2013-435.

As a general finding, the AUC noted that EDTI's proposed escalators for labour costs were consistent with either previous AUC directions in EDTI's last Tariff application, or with negotiated results of collective bargaining agreements. Where the AUC did find minor discrepancies (e.g. escalator costs for non-union employees), the AUC held that such differences were not likely to be significant. In the interest of regulatory efficiency, the AUC did not require EDTI to correct these discrepancies, as such corrections would require substantial time and effort to correct.

The AUC held that all of the projects previously approved in Decision 2013-435 continued to be necessary to maintain service reliability and safety at adequate levels. With respect to the true-up amounts requested, the AUC held that the variance amounts were consistent with the scope, level and timing of the work outlined in the business case provided and approved in Decision 2013-435. The AUC accepted the explanations for each variance as reasonable, with the exception of Information Technology related projects. EDTI withdrew its Information Technology related projects from capital tracker consideration, noting that the capital additions could be fully funded through the I-X mechanism. The AUC held that EDTI would have to re-apply for capital tracker treatment of these projects.

The AUC approved the following new capital tracker programs as necessary projects, holding that they were required during either the 2014 or 2015 forecast period to maintain service reliability and safety at adequate levels:

(a) Outage Management System/Distribution Management System, as EDTI's current outage management software was becoming obsolete and is reaching the end of its useful life;

(b) Capitalized Aerial System Damage, consisting of repairs to EDTI's aerial distribution facilities that are either damaged, or about to fail;

(c) Underground Industrial Distribution Servicing – Rebates, Acceptance Inspections & Terminations, which consists of building new underground 15- and 25-kilovolt primary cables, switching cubicles and ancillary equipment to connect new industrial lots within EDTI's service area;

(d) Replacement of Faulted Distribution Paper Insulated Lead Covered Cable ("PILC"), which consists of repairs and replacements to cables as they occur;

(e) Neighbourhood Renewal program, which contemplates replacement of large portions of electric distribution infrastructure in aging neighbourhoods;

(f) Life Cycle Replacement of Network Transformers, which consists of replacing aging network transformers installed in sidewalk vaults;

(g) Street Light Service Connections and Security Lighting Addition and Capital Replacement, which consists of installing and repairing street lighting, signal and security lighting; and

(h) Life Cycle Replacement of PILC, which consists of replacing PILC that have reached the end of their useful lives.

The AUC held that the Customer Revenue Metering – Growth & Life Cycle Replacements project, which consists of installing revenue meters at new sites and replacing revenue meters at sites that are no longer compliant with Measurement Canada requirements for such meters, would only be eligible for its lower forecast of costs. EDTI submitted that capital tracker treatment for this project was inextricably linked to its Advanced Metering Infrastructure (AMI) project. The AUC was therefore only prepared to approve the lower forecast of $4.19 million for 2015.

EDTI Accounting Test

The AUC held that EDTI's accounting tests were generally consistent with accounting methodologies previously approved in Decision 2013-435. The AUC did direct EDTI to make certain adjustments to the I-X Index, the Q Factor, and weighted average cost of capital rate.

EDTI's 2013 I-X factor was set at 1.71 percent in Decision 2013-072. EDTI applied an I-X factor of 1.59 percent for 2014, as approved in Decision 2013-462. EDTI applied an I factor value for inflation of 2.70 percent. EDTI also applied Q Factors of 0.54 percent for 2013, 1.96 percent for 2014, and 0.64 percent for 2015. However, EDTI noted that its calculations for the 2014 Q factor (which is derived from the approved I-X factor), were not based on the 2013 final forecast billing determinants approved in Decision 2013-270.

The AUC held that EDTI was required to make its preliminary forecasts based on 2013 billing determinants approved in Decision 2013-072. Therefore the AUC directed EDTI to use a 2013 Q Factor of 1.46 percent.

The AUC also held that, because it had determined the 2015 I-X factor and billing determinants forecast for 2015 PBR rate adjustments in another proceeding, the AUC directed EDTI to update its calculations applying the directions in Decision 2014-346.

With respect to weighted average cost of capital, the AUC noted that it expects to render a decision in respect of a common set of assumptions in respect of values comprising weighted average cost of capital as part of Proceeding 3434. Therefore, the AUC directed EDTI to reflect any directed changes from the decision forthcoming for Proceeding 3434 into its compliance filing.

As a result of these directed changes to EDTI's accounting tests, the AUC concluded that it was unable to make a determination as to whether any of EDTI's proposed capital tracker tests satisfied the accounting tests, and therefore reserved any determination until EDTI files its compliance filing. The AUC made no findings as to whether the proposed capital tracker costs satisfied the first criteria of the three-part test capital tracker treatment.

The AUC did however, find that the driver for each of the projects approved as necessary projects satisfied the second criteria of the three-part test capital tracker treatment, in that each of the projects were either an asset replacement or refurbishment, required by a third party, or was growth-related.

On matters of materiality, the third criteria of the three-part test for capital tracker treatment, the AUC noted that EDTI submitted that the primary threshold of four basis points on a project level was approximately $102,000, and the secondary threshold of forty basis points on an aggregate level was approximately $1.017 million for 2013, and applied the escalating I-X factor for subsequent years. The AUC directed EDTI to apply the recently approved 2015 I-X factor and revise its materiality thresholds for 2015 in its compliance filing.

The AUC held that EDTI generally applied the materiality tests appropriately. However, as a result of the AUC's directions to change the accounting tests, the AUC was unable to assess whether the projects identified by EDTI meet the third criteria of the three-part test for capital tracker treatment.

Advanced Metering Infrastructure

EDTI proposed to install Advanced Metering Infrastructure ("AMI") as a solution for customer revenue metering to replace current processes for reading, energizing, de-energizing and enabling more efficient access to end-user information. EDTI proposed to implement the AMI program from 2014 to 2017. The AUC had previously rejected a request by EDTI to implement an AMI project in 2010-2011, as the AUC found that the business case was not well founded, and that Alberta lacked a smart grid policy. EDTI submitted that it had incorporated and updated its business case in consultations with stakeholders and in accordance with Decision 2010-505.

The AUC determined that the updated business case did not suffer from the same drawbacks as EDTI's prior proposal, noting that the directions in Decision 2010-505 have been addressed. The AUC therefore found that the AMI project would represent the least cost solution for customer revenue metering in the long term. However, the AUC noted that the implementation of AMI would result in the wholesale retirement of current meters on EDTI's system, triggering concerns related to asset dispositions, and the treatment of un-depreciated capital.

EDTI applied for capital tracker treatment of its AMI project, but noted that it will not implement the AMI project if its shareholders will be responsible for the remaining net book value of its existing customer revenue meters. The AUC held that this position essentially rendered the issue moot, and directed EDTI to remove the 2015 capital forecast additions of $10.39 million from its forecast K Factor calculation. The AUC did not determine whether the AMI project would qualify for capital tracker treatment, but reiterated that companies may choose to undertake a capital investment at their discretion, and need not wait for AUC approval to proceed.

K Factor Calculation

EDTI submitted that it had calculated its proposed 2013 K Factor true-up amount in accordance with AUC Decisions 2012-237 and 2013-435. EDTI proposed to collect its 2013 K Factor true-up amount through Rider DJ, consistent with Decision 2013-435. EDTI proposed to collect this amount over two months, effective March 1, 2015.

Due to the AUC's directions for EDTI to revise its accounting tests for capital tracker treatment, the AUC could not approve any 2013 K Factor true up adjustments, as the revisions may cause changes to the 2013 K Factor true-up amount. However, the AUC noted that the calculations and methodology used by EDTI in deriving the 2013 K Factor true-up amount were generally consistent with prior AUC directions, including the proposal to collect the amounts through Rider DJ from each rate class.

With respect to EDTI's 2014-2015 K Factor forecast, the AUC noted that it directed EDTI to remove $10.39 million in capital additions associated with the AMI project from the 2015 forecast K Factor calculation (though the AUC made no determination as to whether the AMI project qualifies for capital tracker treatment). Due to this, and the AUC's prior directions for EDTI to revise its accounting tests, the AUC held that it could not approve any 2014 or 2015 K Factor adjustment for EDTI on a forecast basis. However, the AUC noted that EDTI's calculations and methodologies were generally consistent with prior AUC directions.

Accordingly, the AUC ordered EDTI to file a compliance filing in accordance with its findings in this decision, not later than March 3, 2015.

***AltaLink Management Ltd. 2015 Interim Transmission Facility Owner Tariff (Decision 3504-D01-2015)***
***Interim TFO Tariff***

AltaLink Management Ltd. ("AltaLink") applied for approval of an interim, refundable transmission facility owner ("TFO") tariff of $60,787,500 per month, effective January 1, 2015. The requested amount reflects 90 percent of AltaLink's forecast 2015 revenue requirement of approximately $810.5 million, divided on a monthly basis. AltaLink further applied to continue its existing terms and conditions of service.

The AUC previously held that AltaLink should apply for an updated interim TFO tariff, noting the significant shortfall amounts awarded in Decision 2014-258.

AltaLink noted its 2015 forecast revenue requirement increased by $189.1 million from its 2014 revenue requirement of $621.4 approved in Decision 2014-258. AltaLink therefore projected a revenue shortfall of the same amount for the 2015 test period, and submitted that the monthly shortfall of approximately $15,758,333 was material.

AltaLink submitted that the applied for interim rates would still result in a revenue shortfall of $108.5 million on an annualized basis.

The Consumers' Coalition of Alberta ("CCA") and Office of the Utilities Consumer Advocate ("UCA") argued that the increased numbers were untested or overstated, specifically with respect to items for labour escalation, contractor escalation and capital escalation.

AltaLink argued that approval of the 90 percent of 2015 forecast revenue requirement (calculated at $60,787,500 per month) was necessary to cover costs of operations, and was only marginally larger than the amount approved by the AUC in Decision 2014-258 (calculated at $59,953,967 per month).

In weighing the merits of the application, the AUC held that the projected revenue shortfall was material, and therefore some relief was necessary. The AUC approved the requested 90 percent of the revenue requirement as filed on an interim refundable basis, effective January 1, 2015, citing concerns related to rate stability, minimization of rate shock, intergenerational equity, and potential financial hardship to AltaLink if the requested relief was not granted.

The AUC also approved the continued interim application of AltaLink's existing terms and conditions.

***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 |
|---|---|---|
| 2610-D01-2015 | ATCO Electric Ltd. | Addition of Generating Unit – Indian Cabins Generating Station |
| 3421-D01-2015 | ATCO Gas and Pipelines Ltd. | (South) Northeast Calgary Connector Pipeline |
| 3428-D01-2015 | Vanderwell Contractors (1971) Ltd. | 3.6-MW Biomass Thermal Power Plant |
| 3563-D01-2015 | ATCO Gas and Pipelines Ltd. | (South) Scotford Expansion Pipeline and Air Products Delivery Lateral Pipeline |
| 2341-D03-2015 | Grande Prairie Generation, Inc. | Harmattan 187S Substation |

## NATIONAL ENERGY BOARD

***Letter to all Pipeline Companies re: Appendix XV and XVI of the MH-001-2013 Reasons for Decision Abandonment Funding Annual Reporting Forms***
***Abandonment – Annual Reporting Forms***

The NEB sent a letter to pipeline companies notifying them that Reasons for Decision MH-001-2013 required all pipeline companies to provide the abandonment funding reporting form in Appendix XV or XVI by January 31 of each year. The NEB clarified that this annual reporting requirement begins in January 2016 and not 2015.

***Safety Advisory SA 2015-01 Overhead Cranes and Material Handling Equipment***
***Safety Advisory***

The NEB released a safety advisory reminding companies to follow established procedures for pre-operational checks for material handling equipment and overhead cranes, noting that routine inspections revealed a number of non-compliances which may impact worker safety.

The NEB recommended that companies take the following preventive actions to ensure compliance:

(a) Develop applicable, current and relevant equipment management procedures;

(b) Train workers in inspection and operation of equipment; and

(c) Conduct inspections, testing and maintenance pursuant to the schedule outlined in procedures or according to manufacturer's specifications.

The safety advisory notes that companies finding deficiencies in equipment management and training programs must take corrective action, as required by the *National Energy Board Onshore Pipeline Regulations*.

***Safety Advisory SA 2015-02 Positive Air Shutoff Devices on Diesel Engines***
***Safety Advisory***

The NEB released a safety advisory reminding companies to ensure that checklists and procedures ensure that adequate controls are in place to prevent flammable/explosive vapours from entering a diesel engine and potentially causing a fire or explosion, noting previous non-compliances on safety audits.

The NEB recommended that companies take the following preventive actions to ensure compliance:

(a) Evaluate any existing procedures and revise or develop applicable, current and relevant procedures;

(b) Utilize the hierarchy of controls in determining positive shutoff equipment requirements;

(c) Ensure the procedures address the method for confirming the functionality of positive air shutoff equipment prior to entering a hazardous worksite;

(d) Ensure responsible persons are adequately trained; and

(e) Conduct inspections, testing and maintenance pursuant to the schedule outlined in procedures or according to the manufacturer's specifications.

***Plains Midstream Canada ULC 2010 Management and Protection Program Audit Corrective Action Plan Implementation Assessment***
***Management and Protection Program – Corrective Action Plan***

The NEB issued a letter to Plains Midstream Canada ULC ("Plains"), and enclosed Order SO-P384-001-2015 (the "Order"), subsequent to its previous orders in respect of Plains' Corrective Action Plan ("CAP").

The NEB recognized that Plains has made some progress in implementing the CAP, but noted that a total of six additional measures are required to ensure that Plains' pipeline and facilities are maintained and operated in a manner that protects the public and the environment.

Among the measures identified, the Order required Plains to:

(a) List and file for NEB approval, the safety critical tasks, operational controls for mitigating risks, and a demonstration of the process used to revise and maintain such controls prior to January 31, 2015;

(b) Retain an independent third party expert to conduct an audit of its management system and Environmental Protection Program, in order to assess compliance with the *National Energy Board Onshore Pipeline Regulations* ("*OPR*"). The auditor's report must be submitted to Plains and the NEB simultaneously by November 30, 2015;

(c) File, for NEB approval, its quality assurance program;

(d) Retain an independent third party expert to conduct an audit of its Integrity Management Program in order to assess compliance with the

*OPR*. The auditor's report must be submitted to Plains and the NEB simultaneously by November 30, 2016; and

(e) Schedule quarterly meetings with the NEB, providing updates on the progress of its management system, performance of its management, and protection programs until all conditions in the Order have been met.

***Trans Mountain Pipeline ULC on behalf of Trans Mountain Pipeline L.P. (Reasons for Decision RHW-001-2013)***

***Nomination or Capacity Allocation Procedures***

Trans Mountain Pipeline ULC, on behalf of Trans Mountain Pipeline L.P ("Trans Mountain") applied for revisions to its nomination or capacity allocation procedures in Trans Mountain Pipeline ULC Petroleum Tariff No. 92 – Rules and Regulations Governing the Transportation of Petroleum (the "Tariff") pursuant to directions from the NEB in Reasons for Decision MH-002-2012. Trans Mountain applied to the NEB requesting approval of certain Tariff amendments incorporating historical-based verification limits ("HBV Limits") and nomination verification procedures on the Trans Mountain Pipeline (the "Pipeline").

In Decision MH-002-2012, the NEB found that due to forecast supply and market dynamics, the Pipeline's nomination and capacity allocation procedures were likely contributing to ongoing apportionment issues.

In this application, Trans Mountain requested the following Tariff revisions:

(a) Changes to nomination verification procedures in Rule 6.1 of its Tariff;

(b) Incorporation of HBV Limits under Rule 6 based on historical deliveries of petroleum to a facility connected to the Pipeline at a Land Destination, and in this regard determining:

   (i) Whether to use a number of months prior to the nomination date, or a set period time for HBV Limits;

   (ii) Whether to use maximum volume delivered to delivery points not including the Westridge Dock delivery point ("Land Destinations") in any month, or the average volume delivered over the applicable time period in setting HBV Limits;

   (iii) The applicable time period; and

   (iv) Whether to include deliveries redirected from the Westridge Dock or not in setting the HBV Limits; and

(c) Establishing a minimum verification limit at three percent of the Pipeline capacity reserved for deliveries to Land Destinations.

Trans Mountain submitted that in each month since November 2010, monthly nominations have exceeded the capacity of the Pipeline reserved for deliveries to Land Destinations, resulting in apportionment of nominations.

<u>Trans Mountain's Officer Certificate Proposal</u>

Trans Mountain proposed to deal with its apportionment issues by instituting a requirement for shippers to meet verification requirements through the submittal of an Officer's Certificate. Trans Mountain submitted that this procedure would ensure that shippers can satisfy verification requirements while allowing Trans Mountain the ability to monitor nominations, and potentially limit "over-nominations" and thereby reduce apportionment. The Officer's Certificate would require a shipper to have, as of the date of its nomination, the "capability" and "intent" to tender and remove its nominated volumes.

While export shippers on the Pipeline were generally supportive of the change, domestic shippers asserted that Trans Mountain was administering its Tariff in a discriminatory manner. The export shippers submitted that the proposal would justify such discrimination by treating certain delivery points differently, and focuses on the physical limitations of certain shippers, as opposed to commercial practices.

The NEB held that Trans Mountain's proposed Tariff amendments were reasonable, but directed Trans Mountain to modify its proposed wording to mitigate the risk of varying interpretations by shippers, which may create material differences in their ability to acquire Pipeline capacity.

The NEB therefore directed Trans Mountain to amend its proposal to require shippers to verify that:

(a) The shipper has the capability and intent to tender each of its nominated volumes and petroleum types; and

(b) The delivery facility indicated on the nomination has the capability and intent to remove the nominated volumes and petroleum types.

The NEB found that requiring a shipper to verify each petroleum type, rather than aggregate volumes would provide a better representation of each shipper's abilities and intentions to ship on the Pipeline. The NEB also ruled that a shipper's nominations should not exceed a shipper's physical or commercial capabilities.

The NEB held that the Officer's Certificate as proposed, would not in and of itself provide a sufficient solution to Trans Mountain's apportionment issues. However, the NEB held that the Officer's Certificate would assist Trans Mountain in its ability to verify shippers' nominations, and was therefore reasonable, as a shipper would not be allowed to include volumes it believes are available for purchase in the market.

The NEB directed Trans Mountain to include explicit wording to the effect that a shipper must have already entered into a contract to purchase petroleum before making a nomination.

<u>Sumas Delivery Point</u>

During its review of the physical operation of the Pipeline, the NEB found that the Sumas Delivery Point on the Pipeline, was not able to take "Delivery", as that term is defined in the Tariff. However, this operational difference did not warrant any discriminatory treatment for export shippers.

The NEB held that a high degree of coordination with the Puget Sound Pipeline was required in order for the nomination and apportionment procedures on the Pipeline to occur. Therefore, for the purposes of nomination verification and capacity allocation, the NEB held that the Pipeline and the Puget Sound Pipeline form an operationally integrated system, and therefore any nomination verification would apply equally for shippers on the Puget Sound Pipeline.

However, the NEB found that the Tariff and Officer's Certificate, on their own, were insufficient to solve the apportionment and over-nomination issues on the Pipeline.

<u>HBV Limits</u>

On matters relating to the incorporation of HBV Limits into the tariff, the NEB held that the purpose of the verification procedures was to increase the likelihood that a shipper's nomination would align with its capability and intent to supply petroleum to, and remove petroleum from, the Pipeline.

Some shippers expressed reservations that such verification may artificially limit nominations, or create "vintaging" for existing shippers on the pipeline. However, the NEB found that the use of HBV Limits would be appropriate, in that historical deliveries were reasonably demonstrative of a shipper's physical and commercial capability to move volume on the Pipeline.

Trans Mountain did not take an express view on any of the proposed alternatives for tracking HBV Limits. However, Trans Mountain noted that a rolling historical alternative, as opposed to a fixed historical alternative, would provide for greater flexibility in responding to changes in actual usage. Trans Mountain also noted that fixed historical alternatives may effectively grant usage rights to shippers. As between peak and average usage alternatives, Trans Mountain submitted that both would be simple to administer.

Trans Mountain also submitted that shorter time periods used in setting HBV Limits may risk an unusual situation being selected (e.g. shutdown), whereas longer time periods may not accurately represent recent shipper activity. Most shippers were supportive of the rolling alternative and average usage alternative.

The NEB held that a rolling alternative would be appropriate as a measure to reduce apportionment, as it would incorporate the most recent information on a shipper's demand for space, as opposed to fixed alternatives, which could confer firm rights for some shippers. The NEB also held that average, as opposed to peak historical usage would be more appropriate for use in setting HBV limits, as the NEB found that normalized usage better represents the actual needs of shippers rather than peak deliveries on a monthly basis. The NEB noted that when used in connection with a rolling alternative, normalized usage history is more likely to reduce apportionment.

In setting the appropriate time period for setting HBV Limits, the NEB found that a 12-month multiple was necessary to account for seasonality, but found that a 12 month time frame may have the same shortcomings as a peak usage methodology. Therefore, the NEB found that an 18 to 24 month time period was most appropriate.

<u>Minimum Verification Limit</u>

Trans Mountain proposed establishing a minimum verification limit based on historical deliveries, to ensure that capacity remains available for new Land Destinations that would not have a history of deliveries, and that the Tariff have sufficient flexibility to respond to such access requirements. As such, Trans Mountain proposed that the verification limit for a Land Destination be the greater of: a shipper's HBV Limit, or three percent of available capacity.

The NEB found this approach to be reasonable, as it ensured that all shippers have a fair opportunity to access capacity on the Pipeline, and would assist Trans Mountain in fulfilling its common carrier obligations. The NEB therefore approved the minimum verification limit as applied for.

As a consequence of the above findings, the NEB ordered Trans Mountain to file a revised Tariff and Officer's Certificate for approval by February 27, 2015.

***Letter re: Increased Public Transparency for Administrative Monetary Penalties (January 26, 2015)***
***Administrative Monetary Penalties***

The NEB sent a letter to all regulated companies and interested parties, advising that the NEB will begin posting information relating to a Notice of Violation ("NOV") as soon as it has been served. The NOV will be released as part of the NEB's Administrative Monetary Penalties processes under the *Administrative Monetary Penalties Regulations (National Energy Board)*.

In order to promote greater transparency throughout the Administrative Monetary Penalties process, the NEB noted that an NOV will include the following information:

(a) Name of the company or individual believed to have committed the violation;

(b) The issue date;

(c) The region and facility;

(d) The Nature of the violation, including the relevant facts surrounding the violation; and

(e) The amount of the penalty, including identification of the mitigating and aggravating factors that were applied to arrive at the amount.

The NEB also provided notice that it will retroactively post a completed NOV for all previously issued Administrative Monetary Penalties.

***Woodside Energy Holdings Pty Ltd. 18 July 2014 Application for a Licence to Export Liquefied Natural Gas (January 29, 2015 Letter Decision)***
***Licence Application – LNG***

Woodside Energy Holding Pty Ltd. ("Woodside Energy") applied to the NEB for a licence to export liquefied natural gas ("LNG") from an export point near Grassy Point, British Columbia pursuant to section 117 of the *National Energy Board Act*. Woodside Energy's licence application requested the following:

(a) A licence duration of 25 years beginning on the date of the first export;

(b) Annual export volumes of 20 million tonnes of LNG (or approximately 28.95 billion cubic metres, annually); and

(c) A maximum quantity of 807 million cubic metres over the term of the licence.

Woodside Energy submitted that the natural gas proposed for export does not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada. Woodside Energy submitted that the North American and Western Canadian gas resource bases are robust sources of supply and are growing with the development of new technologies. Woodside Energy also submitted that the export of natural gas would not cause any difficulty for Canadians in meeting their natural gas prices at fair market value, due to the open and efficient nature of gas markets in Canada.

Woodside Energy also submitted that although the NEB has issued a large number of LNG export licences for a very large volume of natural gas, not all licences would use their full allocation.

The NEB, agreed with the submissions of Woodside Energy, noting that the market information and general forecasts were consistent with the NEB's own market monitoring information.

The NEB therefore granted the licence for the export of LNG under section 118 of the *National Energy Board Act*, subject to the following conditions:

(a) The annual volumes requested by Woodside Energy are subject to a 15 percent annual tolerance to account for fluctuations (the NEB noted that the tolerance was factored into the maximum term quantity);

(b) The licence will expire if LNG exports do not commence within 10 years; and

(c) The issuance of the licence is subject to approval of the Governor in Council.