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DECISIONS

REGULATORY
LAW CHAMBERS

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

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

IN THIS ISSUE:

FEDERAL COURT OF APPEAL

Hamlet of Clyde River v TGS-NOPEC Geophysical Company ASA (TGS), 2015 FCA 179
Standing – Duty to Consult – NEB Geophysical Operations Authorization

In this decision, the Inuit hamlet of Clyde River, located on Baffin Island, Nunavut ("Clyde River"), applied for judicial review of the NEB's decision granting a Geophysical Operations Authorization ("GOA"). The NEB granted the GOA to TGS-NOPEC Geophysical Company ASA ("TGS"), Petroleum Geo-Services Inc., ("PGS") and Multi Klient Invest ("MKI"). Under the GOA, TGS, PGS and MKI could undertake a two-dimensional offshore seismic survey program in Baffin Bay and the Davis Strait (the "Project") for up to five years. The NEB granted the GOA pursuant to section 5(1)(b) of the *Canada Oil and Gas Operations Act*, RSC 1985, C. O-7 (the "*COGOA*").

The application for judicial review by Clyde River was supported by Jerry Natanine, a resident of Clyde River, and the Nammautaq Hunters & Trappers Organization – Clyde River (collectively, the "Appellants").

The population of Clyde River relies on the harvest of marine mammals, including the bowhead whale and narwhal for food security, and for their economic, cultural and spiritual well-being. The bowhead whale and the narwhal are respectively identified as "threatened" and "Special Concern" by both the *Species At Risk Act*, SC 2002, c. 29 (the "*SARA*") and the Committee on the Status of Endangered Wildlife in Canada (the "COSEWIC").

The following issues were raised on appeal:

(a) Did Clyde River have standing to bring the application for judicial review?

(b) Was the Crown's duty to consult with the Inuit in regard to the Project adequately fulfilled?

(c) Did the NEB err by issuing the GOA, including:

  (i) Whether the NEB's reasons were adequate;

  (ii) Whether the NEB reasonably concluded that the Project is not likely to result in significant adverse environmental effects; and

  (iii) Whether the NEB failed to consider Aboriginal and Treaty rights; and

(d) Was the Crown obliged to seek the advice of the Nunavut Wildlife Management Board ("NWMB")?

<u>Standing</u>

As a preliminary issue, the Attorney General of Canada (the "AG") raised whether Clyde River had standing to challenge the decision. The AG submitted that the Appellants were not directly affected by the NEB's decision, and that Clyde River and the other appellants had no standing to pursue claims based on Aboriginal and treaty rights.

The Court noted that the Appellants were raising serious justiciable issues about the NEB's decision, and whether the Crown's obligation to consult was met. The Court further noted that TGS, MKI, and PGS all consulted with the Appellants throughout the consultative stage of the application.

The Court determined that the Appellants had standing to bring the application noting that a preponderance of factors militated toward granting standing. Therefore the Court proceeded to consider the remaining three issues.

<u>Duty to Consult</u>

The Appellants submitted that the Crown was obligated to consult with the Inuit as a result of the NEB's receipt of the GOA application. The Appellants submitted that the duty to consult was at the high end of the consultative spectrum, requiring meaningful attempts to engage the Inuit in decision-making process, given the impact on marine mammals. The Appellants submitted that the Crown took virtually no action to discharge its duty to consult.

The AG conceded that Canada owed a duty to consult, but argued that it fulfilled such duty to consult at the mid-range of the consultative spectrum, relying on the consultative efforts of the project proponent. The AG also noted that the terms and conditions of the GOA reasonably accommodated the Appellants' concerns regarding potential impacts on harvesting rights.

The Court held that the Crown had a duty to consult, and that the NEB was the body mandated to engage in a consultative process. The Court also noted that this was consistent with the Supreme Court of Canada's prior decision in *Taku River Tlingit First Nation v British Columbia (Project Assessment Director)*, 2004 SCC 74, which upheld the Crown's reliance on environmental assessment processes to fulfil the duty to consult.

With respect to the proper point on the spectrum of consultation required, the Court noted that the Appellants claimed they were owed consultation on the upper range of the spectrum, while the AG conceded only a mid-range level of consultation. The Court found that the appropriate range of consultation was fact specific, and depended in part on the strength of the right being asserted. In this case, the aboriginal right in question was acknowledged by the Crown through the Nunavut Land Claims Agreement which provides the right for the Inuit to continue hunting, fishing and harvesting in the Nunavut settlement area. Therefore, citing both the strength of the right claimed, and the potential environmental effects noted by the NEB, the Court determined that a high level of consultation was warranted with respect to the GOA.

The Court summarized the arguments of the Appellants as twofold:

(a) First, that the Crown rejected their request for a Strategic Environmental Assessment; and

(b) Secondly, that the public participation granted by the NEB was inadequate, and not a proper substitute for formal consultation.

With respect to the first argument, the Court found that consultation did not require a Strategic Environmental Assessment. The Appellants failed to show that the NEB's reasons for rejection of the Strategic Environmental Assessment were unreasonable, and that the ongoing terms and conditions in the GOA for monitoring and reporting effectively ameliorated any uncertainty with respect to environmental effects in the future.

The Court held that the Crown had adequately fulfilled its duty to consult with the Inuit in regard to the Project, citing ongoing meetings between the project proponents and aboriginal communities from 2011 onward, and noting the communities' active participation including several recommendations from aboriginal groups being incorporated into monitoring and surveying. The Court also held that this duty had in part been fulfilled through the environmental assessment process, which under the now repealed *Canadian Environmental Assessment Act*, SC 1992, c 37, required the NEB to consider an "environmental effect" under section 2(1). The Court noted that this definition included the effect of any change that a project may cause in the environment, including "the current use of lands and resources for traditional purposes by aboriginal persons." The Court also found that the terms and conditions were set in such a way for Aboriginal concerns to be expressed throughout the lifecycle of the project, requiring regular environmental assessment updates, and ongoing meetings with potentially affected communities.

No Error in Reasons for Issuing GOA

The Appellants submitted that the NEB gave no reasons for its decision to issue the GOA. The Court ruled that this argument was without merit and therefore dismissed it, noting that the NEB's reasons were set out in both the environmental assessment and in the terms and conditions of the GOA.

The Court found that the NEB did not err in its reasons in issuing the GOA.

Advice of the NWMB Not Required

The Appellants argued that the Crown breached the Nunavut Land Claims Agreement, as Article 15.3.4 required the Crown to consult with the NWMB if it would "affect the substance and value of Inuit harvesting rights and opportunities within the marine areas of the Nunavut Settlement Area."

The Court determined that the Crown had no obligation to seek the advice of the NWMB, finding that the purpose of the NWMB, as set out in the Nunavut Land Claims Agreement, was to be the regulator of access to wildlife, and to make wildlife management decisions. The Court characterized the scope of the NWMB's powers in this capacity as related to wildlife management, and not to decisions such as the issuance of a GOA. Such decisions were therefore not within the purview of the NWMB.

Result

As the Court dismissed each of Clyde River's three substantive grounds of appeal, the Court dismissed the appeals with costs.

ALBERTA ENERGY REGULATOR

Second 2015 Orphan Fund Levy (Bulletin 2015-24)
Bulletin – Orphan Fund Levy

The AER announced the collection of the second orphan levy of $15 million to fully fund the Orphan Well Association's approved budget of $30 million. The first instalment of the Orphan Fund Levy, which is collected pursuant to Part 11 of the *Oil and Gas Conservation Act*, was collected in March 2015 by the AER. The AER calculates a licensee's share of the Orphan Fund Levy with reference to *Directive 006: Licensee Liability Rating ("LLR") Program and Licence Transfer Process*; *Directive 011: LLR Program – Updated Industry Parameters and Liability Costs*; and *Directive 075: Oilfield Waste Liability Program* as follows:

Levy = A/B x $15,000,000

"A" is equal to the licensee's deemed liabilities as of August 1, 2015 pursuant to the above LLR programs. "B" is equal to the sum of the industry's deemed liabilities as of August 1, 2015 pursuant to the above LLR programs.

Orphan Fund Levy invoices were mailed out on August 6, 2015. The bulletin notes that payment of the same to the AER is due no later than September 7, 2015 or a 20 percent penalty will be applied along with an issuance of a Notice of Low Risk Noncompliance in accordance with *Directive 019: Compliance Assurance*. Any licensees appealing the Orphan Fund Levy must do so by September 7, 2015.

Environmental Protection Order to Syncrude Canada Ltd. (August 11, 2015)
Environmental Protection Order

On August 11, 2015, the AER announced an environmental protection order ("EPO") pursuant to section 113 and 156 of the *Environmental Protection and Enhancement Act* ("*EPEA*"). The EPO arises from Syncrude Canada Ltd. ("Syncrude") discovering and reporting the death of approximately 30 Great Blue Herons at or near the Mildred Lake Oilsands Processing Plant and Mine, Aurora North Oil Sands Processing Plant and Mine and Aurora South Oil Sands Processing Plant and Mine (the "Facility") on August 7, 2015. The Great Blue Herons were found in the immediate vicinity of the Southwest Sand Storage Facility External Sump 691 East and 691 West (the "Sumps").

Under the terms of the EPO, Syncrude is required to submit the following information:

(a) Collect and test water and soil samples from the Sumps for substances such as trace metals, alkylated naphthalenes, and napthenic acids, among others prior to August 19, 2015;

(b) Provide an aerial photo and map of the incident area, including monitoring wells;

(c) Identify the current capacity of the Sumps including a description of the product stored and the maximum holding capacity of the Sumps;

(d) Provide a daily report to the Director by 3:00 pm each day, setting out:

  (i) Steps taken in the previous 24 hours to remediate the incident;

  (ii) Steps to be taken in the next 24 hours;

  (iii) Updated inventory of impacted wildlife; and

  (iv) Progress and findings of Syncrude's actions related to the incident;

(e) Provide a daily report to the public, setting out:

  (i) Steps taken in the previous 24 hours to remediate impacts to wildlife; and

  (ii) Steps to be taken in the next 24 hours to remediate impacts to wildlife;

(f) Prepare and submit a Wildlife Mitigation Plan to the Director on or before August 14, 2015, including at a minimum:

  (i) Wildlife fencing around the Sumps;

  (ii) Amphibian fencing/silt fencing to the wildlife fencing currently being constructed;

  (iii) Visual deterrents to wildlife; and

  (iv) Increase the frequency of cannon location rotations;

(g) Prepare and submit a Detailed Delineation and Remediation Plan, including:

  (i) A detailed plan to delineate the full extent of the substances associated with incident in the soils and groundwater;

  (ii) All of the steps to be taken to remediate the substances identified during the delineation at all locations where they are present, including methods of removal;

  (iii) All of the steps for transportation and disposal of recovered substances; and

  (iv) A schedule of implementation; and

(h) Prepare and submit a final report to the Director within 30 days of the completion of all work required under the EPO, summarizing the work undertaken, including a verification that the work has met all standards and criteria as set out by the Director.

A copy of the EPO can be found here.

Bulletin 2015-25: Restrictions to Temporary Diversion Licences (August 14, 2015)
Bulletin – Temporary Diversion Licences

The AER announced restrictions on water withdrawals for current temporary diversion licences ("TDL") due to dry weather and low flow conditions in Alberta. The AER also encouraged oil and gas operators to voluntarily reduce consumption in areas with no mandatory restrictions.

The restrictions come after Alberta Environment and Parks issued a low flow advisory in the Upper Athabasca River basin. The Bulletin extends the restrictions on TDLs to the following watercourses, with the following additional restrictions

(a) Battle River basin;

(b) South Saskatchewan River basin – all TDLs have been suspended in some sub-basins;

(c) Milk River basin;

(d) Peace River basin – all TDLs have been suspended in some sub-basins; and

(e) North Saskatchewan River basin – TDLs are in the process of being suspended in some sub-basins.

The Bulletin advises that no new TDL applications are being accepted for the watercourses listed above. The restrictions will be lifted when river flows return to acceptable levels.

A map of the areas and watercourses currently under water restrictions can be found here.

Updated Alberta Table of Formations (August 18, 2015)
2015 Alberta Table of Formations

The Alberta Geological Survey released the 2015 Alberta Table of Formations, incorporating new knowledge of stratigraphic relationships of rock units in Alberta. The 2015 Alberta Table of Formations was also updated to align with the current naming practices of the North American Stratigraphic Code.

The updated 2015 Alberta Table of Formations is available from the AER, here.

AER Suspension Order to Nexen Energy ULC (August 28, 2015)
Suspension Order

On August 28, 2015, the AER ordered that operations for the following pipeline licence numbers held by Nexen Energy ULC ("Nexen") were immediately suspended: 39427; 39428; 39429; 43961; 51055; 52719; 52773; 52775; 52777; 53285; 53287; 54531; 54599; and 54769.

According to the order, the suspension was to remain in force until otherwise rescinded by the AER.

The AER issued the suspension order to Nexen under section 29(1)(b) of the *Pipeline Act*. Section 29(1)(b) of the *Pipeline Act* provides that:

> **29(1)** Where it appears to the Regulator or its authorized representative that in the construction or operation of a pipeline or in the undertaking of a ground disturbance there has been or is a contravention of this Act, the rules, a licence or an order or direction of the Regulator, or that a method or practice employed or any equipment or installation at a pipeline or in a controlled area is improper, hazardous, inadequate or defective,
>
> …
>
> (b) the Regulator or its representative may order that the construction or operation of the pipeline or the ground disturbance be suspended until further order, or …

The AER directed Nexen to provide sufficient documentation to assure the AER that the suspended pipelines can be operated safely. According to a news release from the AER, the suspension order affected 95 pipelines carrying natural gas, crude oil, salt water, fresh water, and emulsion.

The suspension arises as a result of the AER's investigation into Nexen's recent Long Lake pipeline failure, which revealed information indicating non-compliance with respect to the *Pipeline Act* and *Pipeline Rules* at the Long Lake Facility.

A copy of the suspension order, and the accompanying news release can be found here and here.

Recently, on September 6, 2015, the AER approved a partial resumption of pipeline operations for Nexen's Long Lake oil sands operations for utilities, such as fuel gas, natural gas and water pipelines. As at September 6, 2015, 55 pipelines remained suspended under the AER's order. The news release can be found here.

ALBERTA UTILITIES COMMISSION

ENMAX Power Corporation 2014 Phase I distribution Tariff Application and 2014-2015 Transmission General Tariff Application Compliance Filing (Decision 20124-D01-2015)

Compliance Filing - Distribution Tariff – Transmission General Tariff

ENMAX Power Corporation ("EPC") filed the compliance filings for its 2014 Phase I Distribution Tariff Application ("DTA") and 2014-2015 Transmission General Tariff Application ("GTA") pursuant to Decision 2014-347.

EPC requested approval of the following, to be effective September 1, 2015:

(a) A distribution revenue requirement of $302.1 million for 2014;

(b) A distribution access service ("DAS") adjustment rider of $1.4 million to collect a shortfall for 2014; and

(c) DAS adjustment rate rider schedules and 2015 transmission tariff rate schedules.

In this decision, the AUC only discussed directions 14, 15, 20 and 21 issued in Decision 2014-347, noting that EPC had either fully complied with the remaining directions, or that the outstanding directions were intended for future applications.

With respect to Direction 14, the AUC previously ordered EPC to adjust its return on equity and equity ratio to reflect the AUC's findings in 2191-D01-2015. EPC submitted that it updated its application to reflect the AUC's findings, but requested that the rates be approved on an interim basis, as there were several applications pending before the Alberta Court of Appeal.

The AUC found that EPC reflected the effects of Decision 2191-D01-2015 in its compliance filing, and therefore complied with Direction 14. The AUC determined that it would exercise its discretion pursuant to section 29(7) of the *Alberta Utilities Commission Act* to approve the distribution and transmission rates on an interim basis pending the outcome of the appeal proceedings.

With respect to Direction 15, the AUC previously ordered EPC to use the actual interest costs for any debt issued by the date of its compliance filing. The Office of the Utilities Consumer Advocate (the "UCA") posed an information request to EPC seeking incorporation of actual 2014 costs of debt in its compliance filing. EPC submitted revised debt schedules, noting that the lower than anticipated cost of debt resulted in a reduction of $0.102 million for the distribution function in 2014, and $0.033 million and $0.034 million in 2014 and 2015, respectively, for the transmission function. The UCA submitted that it did not object to the approval of the compliance filing, subject to the inclusion of EPC's revised debt schedules.

The AUC found that EPC reflected its actual debt costs, as submitted in its revised debt schedules, and therefore held that EPC complied with Direction 15.

With respect to Directions 20 and 21, the AUC directed EPC to record its amortization of reserve differences (recognized as a dollar value for each plant account) using the composite remaining life of the assets to ensure a smoother recovery during the period of time between depreciation studies. The AUC also directed EPC to revise its schedule of depreciation accrual rates to reflect the separation of the required annual true-ups that will be recorded as a dollar amount to each account.

EPC submitted that it reflected these two directions in its Minimum Filing Requirements ("MFR") schedules. However, when asked in an information request to reflect the reserve differences as a separate line item, EPC stated that it had determined the amortization of reserve difference amounts on an individual account basis elsewhere in its MFR schedules, and could not separately calculate the amortization of reserve differences on an actual or forecast basis due to constraints in its financial system. In response to an AUC inquiry as to whether EPC would be able to determine a composite depreciation rate that excludes the amortization of reserve differences in its last amortization study, and separately identify the reserve difference amounts on its MFR schedules, EPC responded that it would revise the affected MFR schedules accordingly.

The AUC held that based on EPC's response to further inquiries, EPC has the ability to comply with Directions 20 and 21, and directed EPC to comply with the directions using the format of disclosure provided by EPC in response to the subsequent AUC inquiries submitted on May 13, 2015. The AUC directed EPC to file revised MFR schedules disclosing the amortization of reserve differences as a separate component of depreciation expense within 30 days of the release of the decision.

The AUC found that with the exception of the method used by EPC for the amortization of reserve difference in its MFR schedules, EPC had otherwise complied with the AUC's previous directions. The AUC noted that the amortization method unnecessarily impacted revenue requirement, and therefore approved the revenue requirement amounts as reflected in the revisions submitted by EPC on April 7, 2015 in the amount of:

(a) $299.9 million for 2014 distribution;

(b) $65.4 million for 2014 transmission; and

(c) $74.1 million for 2015 transmission.

The AUC therefore ordered that:

(a) EPC file revised MFR schedules disclosing the amortization of reserve differences as a separate component of the approved April 7, 2015 depreciation expense within 30 days of the release of the decision;

(b) EPC's distribution and transmission revenue requirements were approved as follows:

   (i) 2014 distribution $299.9 million;

   (ii) 2014 transmission $65.4 million; and

   (iii) 2015 transmission $74.1 million;

(c) EPC's 2014 DAS adjustment rider is approved, effective September 1, 2015; and

(d) EPC's 2015 transmission tariff is approved, effective September 1, 2015.

ATCO Electric Ltd. Application for Approval of 2012 Transmission Deferral Account and Annual Filing for Adjustment Balances Second Refiling (Decision 20580-D01-2015)
Compliance Filing – Transmission Deferral Account

ATCO Electric Ltd. ("ATCO") submitted its second compliance filing for its 2012 Transmission Deferral Account and Annual Filing for Adjustment Balances application. The AUC had previously considered the application in Decision 3509-D01-2015 and Decision 2014-283. In both instances the AUC ordered a re-filing, and issued directions to ATCO. In this refiling application, ATCO proposed a one-time refund to the Alberta Electric System Operator ("AESO") in the amount of $30.816 million.

The AUC issued six directions to ATCO in Decision 3509-D01-2015. The AUC determined that ATCO fully complied with Directions 1, 2, and 3.

With respect to Direction 4, ATCO submitted that it removed the disallowed legal costs in the amount of $385,000. With respect to Direction 5, ATCO submitted that it removed the one-time net present value for the NE Loop disallowances from the refund summary schedule, as the present value methodology for truing up capital disallowances was still under consideration in Proceeding 3378. ATCO submitted that it would file an application at a later date to settle the impact of the disallowance.

The AUC determined that ATCO complied with both Direction 4 and Direction 5 from Decision 3509-D01-2015.

The AUC noted that the remaining directions from prior decisions would be considered in future applications, and were therefore not addressed.

As ATCO had complied with all the outstanding directions, the AUC directed ATCO to refund the AESO for the total 2012 annual adjustment amount of $30.816 million in the month of September 2015.

ATCO Gas South 2015 Weather Deferral Account Rider "W" Application (Decision 20466-D01-2015)
Weather Deferral Account – Rider "W"

ATCO Gas, a division of ATCO Gas and Pipelines Ltd. ("ATCO Gas") applied for approval of recovery rates established from the balance (as of April 30, 2015) of its weather deferral account of ATCO Gas South in its southern service area.

ATCO Gas' weather deferral accounts ("WDA") allows ATCO Gas to manage revenue risk to the utility from material differences in actual temperature compared to forecast. Decision 2008-113 originally approved the WDA to be trued up using a 12-month WDA rider for when the account balance exceeded $7 million at April 30th of a particular year, representing approximately a +/- 10 per cent variance from the normalized weather forecast. ATCO Gas had previously received AUC approvals to dispose of a refund amount of $7.245 million and $13.318 million in Decision 2009-093 and Decision 2011-313 respectively as Rider "W".

ATCO Gas submitted that the southern WDA balance as of April 30, 2015 was in a recovery position of approximately $12.591 million, recoverable from ATCO Gas South customers. ATCO Gas submitted that the impacts on customers would be:

(a) A $0.130 per gigajoule charge for low-use customers for an average total of $17.00 annually; and

(b) A $0.130 per gigajoule charge for mid-use customers for an average total of $390.00 annually.

ATCO had originally requested that Rider W be effective from August 1, 2015 to July 31, 2016, later updating its request for a recovery period from September 1, 2015 to August 31, 2016.

The AUC held that ATCO's proposed methodology of calculating the Rider W charge for the WDA was reasonable, and was consistent with previous approvals.

The AUC was also satisfied that the increase in cost to customers would not result in rate shock for customers.

The AUC therefore approved ATCO Gas' south WDA Rider W for implementation from September 1, 2015 to August 31, 2016.

ATCO Gas 2013 PBR Capital Tracker Refiling and True-up and 2014-2015 PBR Capital Tracker Forecast Compliance Application (Decision 20385-D01-2015)
Compliance Filing – Capital Tracker Refiling and True-up – PBR Capital Tracker Forecast

Pursuant to the AUC's directions in Decision 3267-D01-2015, ATCO Gas filed its compliance filing for its 2013 Performance Based Regulation ("PBR") Capital Tracker Re-filing and True-up, and its 2014-2015 PBR Capital Tracker Forecast.

In its compliance filing, ATCO Gas requested additional revenues under its PBR plan for necessary capital expenditures (referred to as K factor amounts) for its North and South service areas, as follows:

(a) 2013 True-up – North: $6,861,000;

(b) 2013 True-up – South: $2,718,000;

(c) 2014 Forecast – North: $13,113,000;

(d) 2014 Forecast – South: $5,878,000;

(e) 2015 Forecast – North: $21,029,000; and

(f) 2015 Forecast – South: $11,404,000.

The updated K factor amounts were, in ATCO Gas' submission, a result of following the 28 directions to ATCO Gas provided by the AUC in Decision 3267-D01-2015.

With respect to direction 2, for ATCO Gas' bare mains replacement program, ATCO Gas submitted that it had reduced its requested K factor adjustment by a total of approximately $656,000. The AUC determined that ATCO Gas had complied with the direction set out in Decision 3267-D01-2015.

With respect to direction 6, for ATCO Gas' allocation and capitalization of overheads for 2013, 2014 and 2015, ATCO Gas submitted that it had reduced its requested K factor adjustment by a total of approximately $64,000 to limit the total pool of overheads to the lesser of the amounts applied for or the I-X increases for each year. ATCO Gas noted that the impact on its depreciation expenses from changes to capitalized overhead would be negligible and therefore made no corresponding adjustments to depreciation. The AUC determined that ATCO Gas had complied with the direction set out in Decision 3267-D01-2015, but ordered ATCO Gas to more clearly link the impacts of its allocated-indirects and K factors in future applications.

With respect to direction 7, ATCO Gas submitted that the discrepancies between schedule A2.5 and A5 in its prior application was that schedule A5 was the correct one for capital additions by program, adding that schedule A2.5 reflected the year-over-year change in construction work in progress for the period 2011-2015. ATCO Gas submitted that this correction to the discrepancy resulted in:

(a) An increase in the North K factor of $211,000 in 2013;

(b) A reduction in the North K factor of $82,000 in 2014;

(c) A reduction in the North K factor of $2,000 in 2015;

(d) An increase in the South K factor of $22,000 in 2013;

(e) An increase in the South K factor of $192,000 in 2014; and

(f) A reduction in the South K factor of $112,000 in 2015.

The AUC determined that ATCO Gas complied with the direction set out in Decision 3267-D01-2015.

With respect to direction 10, ATCO Gas submitted that it updated its Steel Mains Replacement expenditures to reflect the AUC's direction that the expenditures be spread evenly over the 2015-2017 period. ATCO noted that this resulted in a total reduction to the K factor of approximately $5,856,000. The AUC determined that ATCO had complied with the direction issued in Decision 3267-D01-2015, but directed ATCO Gas to continue to identify Steel Mains Replacement adjustments for future K factor filings and other rate base filings until such time as the AUC determines the impact of such adjustments to be insignificant.

With respect to direction 16, the AUC directed ATCO Gas to provide methods for allocating capital cost allowances to capital programs going back to 2001. ATCO Gas provided two possible methods for doing so. The AUC determined that ATCO Gas' two alternative methods for allocating capital cost allowances going back to 2001 did not fully comply with the direction, noting that ATCO Gas was not able to easily estimate the opening undepreciated capital costs for each program. The AUC noted that ATCO Gas appeared to have data for some of its asset classes, and could not determine why ATCO Gas was unable to comply. The AUC noted that it may choose to re-examine the issue in a future proceeding, but determined that it was prepared to accept ATCO's preferred alternative allocation methodology for capital cost allowances for the purposes of this decision.

With respect to directions 13, 14, 17 and 19, ATCO Gas submitted that it had updated its I-X billing determinants and Q factor, its weighted average cost of capital rates approved in Decision 3434-D01-2015, its accounting test, and updated all the I-X index values to 1.49 percent, to reflect the AUC's determinations in Decision 2014-363 and Decision 2013-435. ATCO noted that these adjustments resulted in a total reduction of $404,000 to the 2015 K factor amount for direction 13, and a total reduction of $9,013,000 to the 2013-2015 K factor amounts for direction 14. The AUC determined that ATCO Gas complied with each of directions 13, 14, 17, and 19.

With respect to direction 20, ATCO Gas submitted that it had reassessed whether the adjustments to the requested K factors had resulted in any changes to whether the projects met the appropriate materiality thresholds, and provided an updated table for the K factor costs of the 18 capital tracker programs assessed in Decision 3267-D01-2015. The AUC found that ATCO had appropriately reassessed the materiality of each of the 18 capital tracker programs.

With respect to directions 24, 25 and 26, ATCO Gas calculated the total refund amount to ratepayers as follows:

(a) A refund of $3,731,000 to North service area rate payers, and a collection of $161,000 in interest; and

(b) A refund of $5,727,000 to South service area rate payers, and a refund of $101,000 in interest.

ATCO Gas calculated the rate impacts for refunds associated with the PBR capital tracker adjustments ("Rider S") over the course of September 1, 2015 to December 31, 2015 as being less than 1.3% for impacted ratepayers. The AUC determined that the rate impacts for the Rider S refund between September 1, 2015 and December 31, 2015 were minimal, and therefore approved the proposed refund period.

ATCO Gas also requested the carrying costs of the refund to customers, calculated in accordance with AUC Rule 023: *Rules Respecting Payment of Interest*. The AUC determined that ATCO's methodology for calculating carrying charges payable to ratepayers was appropriate.

The AUC therefore ordered ATCO Gas to refund $9,398,000 to its ratepayers in the North and South service territories through Rider S from September 1, 2015 to December 31, 2015.

FortisAlberta Inc. Disposition of Land in High River (Decision 20271-D01-2015)

Disposition of Land – Outside Ordinary Course of Business

FortisAlberta Inc. ("Fortis") applied for approval to dispose of land located in High River, Alberta outside of the ordinary course of business pursuant to section 101(2)(d) of the *Public Utilities Act*. The land is comprised of 20.66 acres, and located adjacent to the High River Service Centre owned by Fortis.

Fortis had previously applied to construct the High River Service Center as a replacement for an existing adjacent facility, and received AUC approval to do so in Decision 2010-309. Fortis later received approval to dispose of the existing facility in Decision 2010-615.

Fortis submitted that the parcel of land in the current application was not actively used in the provision of utility service. Fortis stated that it previously held the land for potential expansion of the service center, or for centralized inventory services, but after a reassessment of its ongoing needs in 2015, found no reasonable likelihood that the parcel of land would be necessary for the provision of utility service. Fortis submitted that the parcel of land, on a prorated per acre basis, had a net book value of $148,702.

Fortis submitted that it did not have an offer to purchase the parcel, and noted that it was advised that the market value of the parcel may be approximately $3 million. Fortis acknowledged that such a value would exceed thresholds previously established by the AUC as considered outside the ordinary course of business.

Since Fortis is regulated under Performance Based Regulation ("PBR"), it submitted that it would remove the parcel of land from rate base at the time of its next rebasing, and therefore the removal would have no impact on rates until the end of the current PBR term.

The Office of the Utilities Consumer Advocate ("UCA") was generally supportive of the disposition, given that there would be no remediation or environmental costs, and that the costs of the disposition would not be paid by customers. However, the UCA submitted that the removal of the parcel of land from rate base was long overdue, and recommended that the AUC disallow the return, taxes, maintenance and other costs in relation to the parcel, since 2005. In the alternative, the UCA requested disallowing Fortis' carrying costs going back to 2011.

Fortis argued that the UCA's recommendations amounted to retroactive ratemaking, and was unreasonable.

The AUC determined that the retention of land not actively used for utility service can be a prudent course of action where there is a reasonable likelihood that the land may be required as such in the foreseeable future. Given that Fortis purchased the land in 2004 at a time that, it submitted, was a time of high growth, the AUC determined that the retention of the land from 2005-2011 was a reasonable course of action and denied the UCA's requested relief.

For the period from 2011 to 2015, the AUC noted that Fortis had still contemplated some future use of the parcel of land for an inventory facility up until 2015, but shared the UCA's concerns regarding the time elapsed between the completion of the new service center and the proposed disposition. The AUC ultimately accepted Fortis' explanation regarding the decision not to pursue a centralized inventory facility, and found that the relatively small net book value of the parcel had a reasonably immaterial impact on rates paid by customers. However, the AUC noted Fortis' overall lack of internal business cases or documentation to support its application, and directed that in future applications, the AUC would require more substantive evidence to support the utility's assertions regarding the use of property.

The AUC held that the proposed sale was outside the ordinary course of business, noting that the disposition of assets in the order of $3 million was not a frequent occurrence for Fortis, as Fortis had previously applied for only two such similar dispositions. In considering whether the disposition was material to Fortis' rate base, the AUC held that while it would not set a generic materiality threshold for Fortis, it did find that the value of the proposed transaction and the net book value for the current application fell within the range of Fortis' prior approvals for similar dispositions.

With respect to the rate base impacts and proceeds of the sale, the AUC held that it would apply a "no harm" test to ensure the disposition would not negatively affect service quality, service quantity or rates. Given Fortis' confirmations that no costs would be borne by customers, and the lack of any objection on this basis, the AUC determined that the disposition would not have an adverse effect on Fortis' customers.

As Fortis is a utility regulated under PBR, Fortis proposed to remove the asset from rate base at the time of rebasing in 2017, given that PBR revenues are decoupled from actual costs. The AUC accordingly held that it would not require any adjustments to remove the parcel, or its cumulative revenues prior to the expiry of the PBR term. The AUC also noted that the small net book value of the parcel would have a minimal impact on rates, and therefore determined that the parcel of land would be removed at the time of Fortis' next rate application.

Consistent with its previous decisions, the AUC directed that the proceeds of sale and net gain from the disposition are to be for the account of the utility shareholders.

The AUC directed Fortis to confirm the disposition of the parcel of land, and to include details of the disposition in its next rate proceeding.

Alberta Electric System Operator Compliance with Directions 5 through 8 from Decision 2014-242 (Decision 3473-D02-2015)
Compliance Filing

On July 13, 2013, the Alberta Electric System Operator ("AESO") initially filed its application for approval of its 2014 ISO tariff and 2013 ISO tariff update with the AUC. On August 21, 2014, the AUC rendered Decision 2014-242 with respect to this initial AESO application. In Decision 2014-242 the AUC directed the AESO to refile its application to reflect several findings, conclusions and directions in Decision 2014-242, on or before October 20, 2014. On October 20, 2014, the AESO filed its 2014 ISO Tariff Compliance Filing application arising from Decision 2014-242. Subsequently, the AESO filed an amendment to its application on March 16, 2015 (the "Application") for reasons discussed in this decision.

On February 9, 2015, the AUC established two separate modules to test the AESO's compliance with Decision 2014-242:

(a) Directions 1 to 4 and 9 to 11 were assessed in Module 1; and

(b) Directions 5 to 8 were assessed in Module 2.

On June 17, 2015, the AUC released Decision 3473-D01-2015 (Errata) to reflect its findings in respect of Module 1.

This Decision 3473-D02-2015 reflects the AUC's findings in respect of Module 2 (directions 5 to 8).

Directions 5 to 8

The AUC's Directions 5 to 8 from Decision 2014-242 were as follows:

(a) Direction 5: Redraft applicable elements of its terms and conditions to reflect the Commission's findings that the AESO has discretion to move a previously discussed in-service target date for a system project to a later date when a change in key assumptions underpinning the target date has materially changed;

(b) Direction 6: Make it clear in its redraft of the relevant provisions that when a market participant elects to specify an in-service date earlier than the date the AESO had forecast, the present discounted value of all the incremental costs and benefits incurred in order to complete the system project by the requested date, rather than the initial target date, will be deemed to be a participant-related cost for all purposes under the AESO's contribution policy.

(c) Direction 7: Refile its application with the redraft of the provisions noted in Directions 5 and 6; and

(d) Direction 8: Reflect in the AESO's refilling, the AUC's decision to deny the addition of subsection 3(3)(d) of Section 8 to its tariff terms and conditions.

AESO Application

In the AESO's original compliance filing application, the AESO proposed to reword Section 8.3(3) of its tariff terms and conditions as follows:

> **(3)** The **ISO** must include as system-related those costs related to a connection project that are associated with:
>
> (a) non-contiguous components of the project unless such components are included in subsection 3(2) above;
>
> (b) looped **transmission facilities**, which are facilities that increase the number of electrical paths between any two (2) substations, excluding the substation serving the **market participant**, and which exclude any new radial transmission line;
>
> (c) a new radial transmission line that is part of looped **transmission facilities** ~~which, within five (5) years of **commercial operation**,~~; or an enhancement or upgrade to existing **transmission facilities** that were previously classified as system-related; when such **transmission facilities** are ~~planned to become looped as part of~~ included in a critical transmission development or regional **transmission system** project with a planned inservice date, which the **ISO** may revise to a later date at its reasonable discretion, within five (5) years of **commercial operation** of the connection project in accordance with:
>
> (i) ~~in~~ the **ISO**'s most recent long-term **transmission system** plan;
>
> (ii) ~~in~~ a **needs identification document** filed with the **Commission**; or
>
> (iii) ~~as the **ISO** reasonably expects are required in the~~the **ISO**'s reasonable expectation of future **transmission system** requirements;
>
> ~~(d) upgrades or expansions to existing~~ but excluding any costs associated with the advancement of the in-service date of such **transmission facilities** ~~which were previously classified~~that are included as ~~system~~participant-related costs in subsection 3(2)(o) above; and ~~which are utilized by several **market participants**; and~~
>
> (~~e~~c) **transmission facilities** in excess of the minimum size required to serve the **market participant** where, in the opinion of the **ISO**, economics or system planning support the development of such facilities.

The AESO noted that it interpreted directions 5 to 8 from Decision 2014-242 with the following two assumptions:

(a) That its revised terms and conditions apply to both load customers and generating customers; and

(b) That its revised terms and conditions not distinguish between transmission projects that alleviated congestion and those that did not.

On February 9, 2015, the AUC provided a letter of clarification addressing the AESO's assumptions, which it noted were incorrect. The AUC explained that directions 5 through 8 were largely based on the examination of the Salt Creek 977S to Black Fly 934S transmission line project considered in Decision 2014-242. The AUC also explained that it did not require that the revised tariff provisions also apply to the advancement of system projects for which compliance with sections 15(1)(e) and (f) of the *Transmission Regulation* established the need to relieve system congestion. In response, on March 16, 2015, the AESO filed an amendment to its original compliance filing application.

The AESO submitted that it would classify costs for new looped facilities or for enhancements or upgrades as follows:

AESO proposed cost classification	**Facilities relieve congestion**	**Facilities do not relieve congestion**
New looped facilities	Costs classified as system-related under s. 8.3(3)(a) of the AESO tariff terms and conditions.	Costs classified in part or in full as participant-related in accordance with advancement costs provisions, pursuant to s. 8.3(2)(b) and s. 8.4 of the AESO tariff terms and conditions.
Enhancement or upgrade to existing facilities	Costs classified as system-related under s. 8.3(3)(a) of the AESO tariff terms and conditions.	Costs classified in part or in full as participant-related in accordance with advancement costs provisions, pursuant to s. 8.3(2)(b) and s. 8.4 of the AESO tariff terms and conditions.

In this decision the AUC provided a brief overview of "system-related" and "participant-related" costs with reference to the AESO tariff. Under the AESO tariff contribution policy, costs for new transmission projects are deemed to be either "participant-related" or "system-related". "Participant-related" costs are paid by the party requesting the advancement of an in-service date. The exact amount of "participant-related" costs are tested against the maximum investment levels under the AESO tariff contribution policy. Where total "participant-related" costs exceed the maximum investment allowance, a market participant must contribute the excess amount. This is contrasted with "system-related" costs, whereby the market participant bears no direct cost for the construction, and the entire cost is borne by the AESO, and paid through the AESO tariff.

The AESO proposed that all costs for new radial transmission lines would be classified as participant-related, except to the extent that if the new radial transmission facilities were part of a planned looped configuration to be developed within the next five years. However, the AESO proposed that if a new radial line was part of a planned looped configuration, costs for the new radial line would only be considered participant-related if other transmission facilities had to be advanced as a result of a market participant's request for an advanced in-service date.

The AESO proposed to classify all looped transmission facilities as system-related. However, on the issue of enhancements or upgrades to transmission facilities, the AESO proposed to classify enhancements and upgrades as system-related if they relieved congestion on the transmission system. The AESO proposed to classify enhancements that did not relieve congestion as participant-related, only if the upgrade or enhancement was not planned within the next five years.

<u>AUC Decision</u>

The AUC held that the AESO's interpretation of the AUC's clarification letter of February 9, 2015, may have led to an understanding that the classification scheme of system-related or participant-related costs needed to reflect whether a project was planned to relieve congestion. The AUC held that it had expected the AESO instead "to focus on determining how to send price signals through the tariff to a market participant who has requested an in-service date that is on the critical path to completion of a transmission project." The intent, according to the AUC was to create tariff provisions that might induce market participants to either shift the in-service date, or absorb relevant incremental costs from the market participant's refusal to shift the in-service date.

The AUC noted it's significant concern that the revised classification scheme would not result in any change in behaviour by the end-use load customer to make an economic decision to shift its in-service date. Therefore, the AUC found that the AESO did not comply with directions 5 to 8 set out in Decision 2014-242.

The AUC determined that resolution of this issue was unlikely to be achieved through further compliance filings and therefore did not provide additional direction as to further adjustments to Section 8.3 of the terms and conditions of service. The AUC ordered that the terms and conditions of service set out in Section 8.3 of the AESO's 2011 tariff (approved in Decision 2011-275) will continue to apply.

<u>AUC-Initiated Generic Proceeding</u>

The AUC noted that the matters raised in this proceeding signalled a need to address whether and how customer advancement costs can be used to ensure that the future development of transmission projects is achieved in both a timely and an economic manner. Therefore, the AUC indicated its intention to address this matter in a separate, AUC-initiated proceeding under section 8(2) of the *Alberta Utilities Commission Act*.

The AUC identified the following issues for consideration in such a proceeding:

(a) The proper balance between the provision of adequate price signals and certainty with respect to the classification of system transmission project advancement costs;

(b) The effect of section 15(1)(e) and (f) of the *Transmission Regulation* on the classification of advancement costs under the AESO tariff;

(c) AESO discretion in applying advancement costs in respect of system transmission projects, and the need to develop clear criteria for the same;

(d) Whether specific changes to the proposed wording of certain tariff provisions are necessary in order to ensure that advancement cost provisions are utilized when necessary;

(e) The application of advancement cost provisions to circumstances where non-radial system transmission projects or upgrades/enhancements of existing system transmission facilities may be made subject to advancement cost provisions;

(f) Why routine system-related classification has occurred for enhancements or upgrades to transmission facilities serving distribution utilities, and considerations of parity between distribution utilities and direct connect customers;

(g) Time limitations on participant-related classification of system project advancement;

(h) The impacts of system transmission project advancement cost provisions on transmission system planning and project execution, and what, if any requirements must be included in the tariff provisions to clarify the role expected of a transmission facility owner in relation to such provisions;

(i) The adequacy of market participant accountability mechanisms in the AESO tariff that may provide market participants with incentives to provide information that the AESO can rely on to ensure that it obtains the best solution to its respective obligations; and

(j) Issues related to Good Electric Industry Practice, specifically whether temporary generation solutions should be considered during periods of low contracted load where a market participant's load is to be staged over time under the contribution policy.

NATIONAL ENERGY BOARD

Regulations amending the National Energy Board Act Part VI (Oil and Gas) Regulations, P.C. 2015-1176 (July 31, 2015)
Amendment - National Energy Board Act Part VI (Oil and Gas) Regulations

The NEB announced that the Governor General in Council made the following amendments to the *National Energy Board Act Part VI (Oil and Gas) Regulations*:

> **10.1** For the purposes of subsection 119.01(1.1) of the Act, "natural gas" means a mixture of gas that is composed of at least 85% methane and that may also contain other hydrocarbons that at a temperature of 15°C and an absolute pressure of 101.325 kPa are in a gaseous state, as well as minor amounts of non-hydrocarbon gas and impurities.

The amendment comes into force immediately.

The Regulatory Impact Analysis Statement ("RIAS"), while not part of the regulation itself, provides useful commentary and context to the changes. The RIAS notes that "natural gas" though commonly known and used throughout the regulations, was not specifically defined in the *National Energy Board Act*, or the regulations made thereunder. The RIAS notes that the objective of the amendment is to define "natural gas". The intended aim is to allow Canadian liquefied natural gas ("LNG") export facilities and exporters some degree of flexibility in the composition of natural gas to be exported under 40-year licences. Such exporters are not allowed to export natural gas with high concentrations of natural gas liquids under the same 40-year licences.

The amendment will allow the NEB to consider natural gas export licence applications for terms longer than 25 years, and up to a maximum term of 40 years.

The full text of the amendment and RIAS can be found here.

NEB postpones Trans Mountain Expansion Oral Hearings (August 21, 2015 Letter Decision)
Oral Hearing Postponed

The NEB announced that it was postponing the oral portion of Hearing Order OH-001-2014 for the Trans Mountain Expansion Project (the "Project"), and that it was further taking the step of striking from the record all evidence prepared by or under the direction of Mr. Steven J. Kelly of IHS Global Canada Limited in Hearing Order OH-001-2014.

The NEB's reasons for taking such steps were driven by the appointment of Mr. Kelly as a full-time member of the NEB by the Governor in Council on July 28, 2015. The appointment becomes effective on October 13, 2015. Mr. Kelly had filed written evidence on the issues of oil market supply and demand in support of the Project. The NEB noted Mr. Kelly's "dual role", as both a future board member and a person who had filed evidence for the Project, may raise concerns about the integrity of the hearing process.

The NEB noted that the decision to strike the evidence from the record of the Project and to postpone the oral portion of the hearing were of the NEB's own volition.

As a result of striking the evidence from the record, the NEB indicated that it would postpone current procedural steps and directed Trans Mountain to provide the following information on or before August 28, 2015:

(a) A list of all evidence prepared by or under the direction of Mr. Kelly in Hearing Order OH-001-2014; and

(b) Advise the NEB whether Trans Mountain intends to replace the evidence (and if so, the date by which the evidence could be filed with the NEB and served on interveners).

The NEB noted that interveners may file comments on Trans Mountain's submissions by September 4, 2015. Trans Mountain may reply to the interveners' comments on or before September 11, 2015.

The NEB advised that, following any comments received, the panel will issue a procedural update for its review of the Project.

Bear Head LNG Corporation Application for a Licence to Export and Import Natural Gas; Pieridae Energy (Canada) Ltd. Application for a Licence to Export and Import Natural Gas (August 13, 2015 Letter Decisions)
Licence to Export and Import Natural Gas

Bear Head LNG Corporation ("Bear Head") and Pieridae Energy (Canada) Ltd. ("Pieridae") each separately applied to the NEB for:

(a) A licence to export natural gas in the form of liquefied natural gas ("LNG"); ("Export Licence") and

(b) A licence to import natural gas. ("Import Licence").

Bear Head requested the following terms for its Export Licence:

(a) 25 year term starting on the date of the first export;

(b) Maximum annual export quantity of 19.4 billion cubic metres;

(c) Maximum term export quantity of 453 billion cubic metres;

(d) A point of export at the outlet of the loading arm of the LNG facility to be located in Richmond County near Point Tupper, Nova Scotia; and

(e) An early expiry if exports have not commenced within 10 years of the issuance of the Export Licence.

Bear Head requested the following terms for its Import Licence:

(a) 25 year term starting on the date of the first import;

(b) Maximum annual import quantity of 14.2 billion cubic metres;

(c) Maximum term import quantity of 356 billion cubic metres;

(d) A point of import at which the Maritimes & Northeast Pipeline crosses the Canada-United States border near St. Stephen, New Brunswick or as otherwise directed by the NEB; and

(e) An early expiry if imports have not commenced within 10 years of the issuance of the Import Licence.

Pieridae requested the following terms for its Export Licence:

(a) 20 year term starting on the date of the first export;

(b) Maximum annual export quantity of 16.675 billion cubic metres;

(c) Maximum term export quantity of 333.5 billion cubic metres;

(d) A point of export at the outlet of the loading arm of the LNG facility to be located in the vicinity of Goldboro, Nova Scotia, and highway and railway crossings along the international border between the province of New Brunswick and the state of Maine; and

(e) An early expiry if exports have not commenced within 10 years of the issuance of the Export Licence.

Pieridae requested the following terms for its Import Licence:

(a) 20 year term starting on the date of the first import;

(b) Maximum annual import quantity of 11.845 billion cubic metres;

(c) Maximum term import quantity of 236.9 billion cubic metres;

(d) A point of import at which the Maritimes & Northeast Pipeline crosses the Canada-United States border near St. Stephen, New Brunswick; and

(e) An early expiry if imports have not commenced within 10 years of the issuance of the Import Licence.

Bear Head and Pieridae both submitted that the quantity of LNG proposed for export would not exceed the surplus remaining after allowance for foreseeable consumption in Canada. Bear Head provided three reports forecasting Canadian consumption, long term gas supply and demand forecasts, and an outlook of Canadian LNG exports. Each of Bear Head's and Pieridae's reports noted that Canada's gas markets were open and liquid, supplied by a robust resource base, and with increased imports from the lower 48 states. Bear Head included nearly all of the NEB approved exports in its forecasts, up to 18 Bcf/d, despite Pieridae's and Bear Head's submission that the full approved LNG export volumes would likely not all materialize. Bear Head and Pieridae noted that the likely range of exports would be far closer to the low end of its forecasts than the full amount.

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

A number of parties submitted letters of comment concerning the development of infrastructure in Nova Scotia, and utilization factors on existing facilities.

However, the NEB determined that such considerations were outside the scope of the NEB's jurisdiction on natural gas export licence applications, and declined to consider the issues.

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

The NEB approved the requested points of import export of LNG for both Bear Head and Pieridae.

The NEB issued the Export Licences and the Import Licences to Bear Head and Pieridae as requested, subject to approval of the Governor in Council, having found that the quantity of gas to be exported by Bear Head and Pieridae would be surplus to Canadian needs.