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DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA ENERGY REGULATOR

Bulletin 2016-09: Alignment of Reclamation Application Process with Responsible Energy Development Act Statement of Concern Requirements
Reclamation Applications – Bulletin – Statement of Concern

The AER announced that, effective immediately, it implemented changes to Section 8.0 (landowner contact requirements) of the *2010 Reclamation Criteria for Wellsites and Associated Facilities Application Guidelines* ("Guidelines") to make the process consistent with the AER's own processes under the *Responsible Energy Development Act* for filing statements of concern.

Accordingly, in lieu of providing a copy of the "Upstream Oil and Gas Facility Complaint Form" to affected parties, applicants must instead provide a copy of the following:

- EnerFAQs "Expressing Your Concern – How to File a Statement of Concern About an Energy Resources Project";
- The form "Statement of Concern About an Energy Resource Project"; and
- Once an application has been submitted to the AER, a copy of the public notice of application from the AER website.

The AER noted that the remainder of the Guidelines continue to apply.

A full text copy of the previous version of the Guidelines can be found here. An updated version of the Guidelines was not provided with Bulletin 2016-09.

Bulletin 2016-10: Obligations of Licensees When in Insolvency or When Otherwise Ceasing Operations
Bulletin – Insolvency – Licensee Obligations

The AER released Bulletin 2016-10 to remind its licensees of statutory responsibilities when ceasing operations, whether due to insolvency or other reasons.

The AER noted that licensees remain responsible for complying with all AER requirements, including:

- Ensuring continued care and custody of all AER-licensed properties;
- Responding to any incidents or complaints;
- Maintaining records of AER-licensed properties in accordance with AER requirements; and
- Either obtaining approval from the AER under Directive 006: *Licensee Liability Rating Program and Licensee Transfer Process* to transfer licenses, approvals, and permits to an eligible party with a Liability Management Rating of at least 1.0 post-license transfer; or completing abandonment and reclamation of all sites in accordance with AER requirements; or posting applicable security under Directive 006.

The AER further noted that failures to comply may result in the AER pursuing enforcement action against the licensee, which may include naming individual directors and/or officers of the licensee under section 106 of the *Oil and Gas Conservation Act*.

The AER also reminded licensees that no licensee or its creditors may remove equipment from a site for any purpose without the AER's consent, including during the conduct of abandonment or reclamation work. The AER noted that any debts owed to the AER by a licensee are also subject to a lien by the AER which takes priority over all other liens, charges, rights of set-off, mortgages and any other security interests pursuant to section 103 of the *Oil and Gas Conservation Act.* A lien by the AER applies to a licensee's interest in any wells, facilities and pipelines, and land or interests in land, including mines and minerals, equipment, and petroleum substances.

Bulletin 2016-11: Conditions in Alberta Energy Regulator Approvals Relating to Participation in the Cumulative Environmental Management Association
Bulletin – Terms and Conditions – Approvals

The AER announced changes relating to the operation of to the Cumulative Environmental Management Association ("CEMA") as it relates to the obligations of approval holders under the *Environmental Protection and Enhancement Act* ("*EPEA*") and any terms and conditions granted under *EPEA*.

The AER noted that CEMA ceased operations on April 1, 2016. Accordingly, and effectively immediately, the AER announced that any term or condition related to mandating an approval holder's participation in CEMA is inoperative.

However, the AER noted that to the extent that a term or condition required any action beyond participation in funding of CEMA, the operational intent of the term or condition would survive without the requirement to undertake the condition through CEMA.

The AER noted, as examples, where an approval requires monitoring, reporting, or research through CEMA, the requirement to participate in CEMA is inoperative, but the requirement to monitor, report or research remains in full force and effect.

Pembina Pipeline Corporation Applications for Two Pipelines Fox Creek to Namao Pipeline Expansion Project (2016 ABAER 004)
Facilities – Pipeline Expansion

Pembina Pipeline Corporation ("Pembina") applied to the AER pursuant to the *Pipeline Act* to construct and operate the following:

- A 609.6 millimetre (24 inch) pipeline; and
- A 406.4 millimetre (16 inch) pipeline,

(Collectively, the "Fox Creek Pipeline").

The Fox Creek Pipeline would run parallel to one another in a common ditch for approximately 268 kilometres, carrying up to 420,000 barrels per day of high-vapour pressure hydrocarbons ("HVP"), low-vapour pressure hydrocarbons ("LVP") and crude oil running from Pembina's Fox Creek pump station at LSD 08-36-062-20W5M to the Namao Junction pump station at LSD 04-35-054-24W4M.

Pembina applied for 15 pipeline agreements in the area covered by the forested portion of the province of Alberta, that includes the mountains and foothills along Alberta's Western boundary (the "Green Area") for access to a permanent right-of-way ("ROW"). Pembina applied for approval of a conservation and reclamation plan including a construction and post-construction reclamation plan along the settled portion of the route within the province of Alberta, encompassing the populated southern, central and Peace River areas (the "White Area").

The following parties raised concerns, were granted standing, and ultimately participated in the hearing before the AER:

- Alexander First Nation ("AFN");
- Driftpile First Nation ("DFN");
- Grassroots Alberta Landowners Association, representing a group of 38 landowners ("Grassroots");
- Gunn Métis Local 55 ("Gunn Métis"); and
- D. Nielsen, ("Nielsen").

<u>Issues</u>

The AER set out the following issues that were considered throughout the course of the hearing, pursuant to section 15 of the *Responsible Energy Development Act*, and section 3 of the *Responsible Energy Development Act General Regulation*:

- The social and economic effects of the Fox Creek Pipeline;
- The effects of the Fox Creek Pipeline on the environment;
- The interests of landowners;
- The impacts on landowners as a result of the use of the land for the Fox Creek Pipeline.

The AER further considered the following issues in the course of the hearing:

- Adverse impacts of energy resource activity on aboriginal rights not addressed in the above list;
- Whether the project provides for the efficient and orderly development of Alberta's energy resources;
- Suitability of the proposed route;
- Whether the Fox Creek Pipeline can be constructed and operated safely; and
- Potential risks to or impacts on historical resources.

<u>Orderly Development</u>

The AER noted that the test it applied in considering this issue was two-fold. First it would consider whether the Fox Creek Pipeline was needed. Second, it would consider whether the Fox Creek Pipeline gave rise to any proliferation issues (i.e. that it is not duplicative of other facilities with sufficient capacity to transport the product).

Regarding the need, Pembina submitted that the liquids rich production in the Fox Creek area has grown, and that its current systems are operating at or near full capacity. Pembina also submitted that the Fox Creek Pipeline is supported by executed transportation agreements with shippers for approximately 360,000 barrels per day of capacity on the Fox Creek Pipeline, or 86 percent of project capacity.

None of the interveners presented evidence regarding the need for the Fox Creek Pipeline, or the proliferation of facilities.

The AER therefore held that Pembina's Fox Creek Pipeline would provide for the orderly and efficient development of Alberta's energy resources, and that the Fox Creek Pipeline would be in the public interest.

Stakeholder Engagement

Pembina submitted that it began stakeholder consultation in 2013, and had met with approximately 250 landowners requesting consent for surveys and various other permissions to define a potential route. Pembina also submitted that it consulted with affected industry parties, and conducted open houses in six different locations to discuss the Fox Creek Pipeline.

Nielsen submitted that he was not consulted with by Pembina with regard to potential rerouting of the Fox Creek Pipeline to the north of an existing ROW on his land.

Pembina submitted that it provided two alternate routes, one of which crossed Nielsen's lands. Nielsen rejected any routes that crossed his lands.

The AER determined that the evidence was not sufficiently clear to draw a conclusion regarding the extent to which Pembina consulted with Nielsen on achieving a satisfactory route. The AER however found that Pembina did attempt to be responsive to Nielsen's concerns, and that there was no evidence that Nielsen made efforts to meet with Pembina to resolve his concerns.

The AFN also raised concerns regarding Pembina's consultation efforts.

Pembina submitted that it engaged in a number of meetings with AFN representatives, and investigated potential reroutes at the request of AFN leadership. However, after a breakdown in communication, Pembina submitted it was told not to contact AFN, except through its senior regulatory coordinator, and that all future meetings be attended by the president and chief executive officer of Pembina.

The AER determined that Pembina was not responsive to the AFN's request. However, the AER held that the evidence demonstrated that Pembina engaged in efforts to consult with AFN, and the panel stated that it hoped the parties would continue to engage in a meaningful way.

Accordingly, the AER held that Pembina's consultation efforts were adequate.

Emergency Response Plans

The AFN submitted that they had not been included in Pembina's Emergency Response Plan ("ERP") mandated by Directive 071: *Emergency Preparedness and Response Requirements for the Petroleum Industry* ("Directive 71").

Pembina submitted that it had developed and filed an ERP pursuant to Directive 71, which was deemed technically complete by the AER on January 26, 2015.

The AFN submitted that it was a "local authority" under Directive 71, and ought to have been consulted. The AFN also submitted that Pembina was required to consider the AFN's future land use operations in planning its ERP.

The AER clarified that Directive 71 requires "licensees" to include members of the public and local authorities within and adjacent to the planning zone. Therefore, the AER determined that AFN would be one of a number of local authorities that Pembina will have to notify and consult with in preparing its ERP for approval prior to commencing operation of the Fox Creek Pipeline. However, the AER held that Pembina is not required to base its ERP or emergency planning zone calculations on future land use, but noted that companies must update their ERP annually, so that plans can accommodate growth near facilities requiring an ERP.

Social and Economic Impacts

The AER noted that Pembina provided limited evidence on the economic and social effects of the project, noting that the majority of the evidence the panel found useful was elicited from written information requests and through oral examination concerning employment estimates, community investment, capital costs, and opportunities for First Nations.

Pembina estimated the capital cost of the Fox Creek Pipeline was approximately $2.4 billion. The panel noted that related expenditures from oil and gas producers expected to use the infrastructure were not provided.

Pembina provided letters of support from Woodlands County and Whitecourt, two communities that stated they expected to benefit economically from the construction and operation of the Fox Creek Pipeline.

Pembina submitted that it had spent $15 million to date to support local aboriginal businesses, but did not provide an estimate of total spending as part of its aboriginal procurement strategy for the Fox Creek Pipeline.

The AFN, DFN and Gunn Métis provided evidence that the Fox Creek Pipeline may alter the timing of harvesting activities, or inhibit the use of traditional-use areas for a period of time.

The AER found that such impacts on traditional use by first nations would be limited to the construction period, which it noted was temporary and imposed for safety reasons. The AER held that Pembina had also committed to mitigate any such impacts.

With respect to the post-construction period, Pembina submitted that incremental royalties from production that would otherwise be shut-in due to transportation constraints were an economic benefit due to the Fox Creek Pipeline. However, Pembina did not provide any specific amounts or estimates of such benefits.

Pembina submitted that the Fox Creek Pipeline would result in the creation of 12 to 15 full time jobs in the local area. Pembina also submitted that it expected to increase its charitable an non-profit investment in the local area by approximately $150,000 per year.

The DFN provided evidence of harmful economic effects on local trappers, who are required to pay fees to maintain trap lines, and that in disturbed areas, they are often not able to trap enough animals to cover their costs, but did not provide specific estimates of such impacts.

The AER held that any negative social or economic impacts from the Fox Creek Pipeline were expected to be short term, temporary and localized, and would be offset by short and long term positive regional and provincial economic effects.

Routing

Pembina submitted that it took into consideration the following factors to develop its preferred route:

- Avoiding residences and other developments;
- Crossing roads, highways and railways at right-angles;
- Minimizing the number of crossings;
- Avoiding wet, rocky or forested areas;
- Crossing rivers with stable banks and where the river is not likely to migrate over time;
- Following existing disturbances;
- Reducing construction by using temporary workspaces on existing disturbances; and
- Using as short and direct a route as reasonably possible.

The AER held that Pembina's route selection criteria were appropriate.

Pembina submitted that after its review of route options, it preferred to parallel the Alliance Pipeline Ltd. ("Alliance") pipeline for a significant portion of the route. Pembina submitted that paralleling its existing Peace pipeline would be problematic due to the proximity to residential access roads, residential developments and Highways 37 and 43, which would cause construction issues, and result in a greater number of road crossings.

Pembina submitted that the Alliance route and the Peace pipeline route were approximately equivalent in length, and Pembina preferred the Alliance route due to fewer construction constraints and fewer crossings.

The AER held that Pembina considered appropriate alternative routes, and that Pembina followed relevant and appropriate routing criteria for its applied-for route.

Safe Operation of the Fox Creek Pipeline

With respect to the safe operation of the Fox Creek Pipeline, the AER determined that the hearing participants did not raise specific issues related to the design of the Fox Creek Pipeline. Accordingly, the AER determined that upon review of the engineering and design of the Fox Creek Pipeline, that Pembina met or exceeded the regulatory requirements and applicable standards, for design and construction, leak detection, integrity management and valve placement.

The AER imposed a condition on Pembina to install additional block valves in the vicinity of the Paddle River to limit any potential damage in the event of an accidental leak, citing Pembina's commitment to install an additional block valve on each pipeline at the Paddle River.

Environmental Effects

The Fox Creek Pipeline would traverse both the Green Area and the White Area. Pembina noted that the Fox Creek Pipeline had the potential to affect a number of components of the physical environment, including vegetation, terrestrial and aquatic species.

Pembina proposed to construct both pipelines of the Fox Creek Pipeline within a single ditch in a ROW that is 35 metres in width, with an additional 10 metres of temporary workspace.

Several interveners raised concerns about the width of the ROW, arguing that it was unnecessarily wide, and recommended that the width be reduced to 25 metres.

Pembina maintained that the 35 metre ROW would be necessary for long-term operations and pipeline integrity excavations throughout the life of the project. However, Pembina did narrow the ROW to 25 metres in areas where the proposed pipeline route paralleled existing ROWs for additional workspace.

Pembina submitted that it would not undertake ongoing vegetation management or brush control for tree species in key wildlife and biodiversity zones ("KWBZ") following construction.

The AER held that it did not have specific requirements for ROWs for pipelines, but noted that it had the authority to direct the reduction of a ROW size where appropriate. The AER held that Pembina planned the ROW to ensure that pipeline integrity activities could be done safely, and accordingly accepted the ROW width for construction.

However, the AER also noted its concern for ongoing brush control over a 35 metre ROW, especially in the Green Area. The AER held that through the creation of a revised operation vegetation management plan, the long-term footprint of the Fox Creek Pipeline could be reduced.

With respect to routing options, Pembina submitted that it selected its preferred route partially with a view to using existing disturbances, corridors or ROWs and avoiding water bodies to the extent practical to reduce environmental impacts. However, Pembina submitted that it was not planning on reducing its ROW width in environmentally sensitive areas, due to its aforementioned integrity assessment requirements.

The AER found that Pembina's overall mitigation efforts were reasonable, such as paralleling existing disturbances. The AER also encouraged Pembina to examine opportunities to narrow or not to clear the entire ROW, revegetate the ROW and other workspaces within the environmentally sensitive areas, or to consider other approaches to construction to further reduce environmental impacts.

Pembina submitted that with respect to wildlife, the Fox Creek Pipeline would traverse approximately 14.2 kilometres of KWBZ in the Green Area, and approximately 2.5 kilometres in the White Area, resulting in a total disturbance area of 41.9 hectares. In order to reduce impacts on waterways in KWBZs, Pembina proposed to use horizontal drilling techniques to avoid impacts to habitat in waterways.

The AER held that the horizontal drilling approach was reasonable, provided that Pembina replace any tree species cleared at the drilling entry and exit points.

The DFN raised concerns about several species of wildlife that would be impacted by the Fox Creek Pipeline. The DFN raised concerns that the proposed route traversed 81.4 kilometres of grizzly bear habitat.

Pembina stated that its use of existing disturbances would minimize the creation of linear disturbances and thereby limit further human access to the grizzly bear habitat. Pembina also committed to place barriers at existing access points to restrict access to the ROW.

The Gunn Métis and DFN submitted evidence that the construction of the Fox Creek Pipeline would cause habitat fragmentation, affecting game species such as moose, elk and grouse that are harvested by its members. DFN submitted evidence describing the difficulty in harvesting sufficient quantities of moose to support cultural activities.

Pembina submitted that it would conduct clearing and construction during winter, which would reduce the impacts on grouse nesting, and would verify the locations of salt lick locations used by moose and committed to ensure that effects on such locations are mitigated.

The AER held that it was satisfied that Pembina's mitigation measures would minimize risks to wildlife, including the grizzly bear.

<u>Landowner Impacts</u>

The Grassroots group of landowners did not oppose the development of the Fox Creek Pipeline, but did have a large number of concerns.

Pembina stated that it typically enters into private agreements with landowners to develop appropriate strategies and mitigation measures, but stated that it had been prevented from meeting with most Grassroots members to view their lands.

The AER noted that many of the individual concerns raised by Grassroots are ones for which the AER had no specific requirements. However, the AER determined that appropriate mitigation measures were most effectively determined through on-site evaluation and direct discussions. Accordingly, the AER declined to rule on the concerns raised by landowners related to: depth of cover, tile drainage issues, access during construction, cattle crossings, reclamation of water sources for cattle, and microrouting issues, among others.

Pembina later filed a table of commitments in response to concerns raised by landowners, which the Grassroots members indicated were satisfactory upon initial review.

The AER therefore held that Pembina's commitments to landowners were reasonably responsive to landowners' site specific concerns and would minimize environmental impacts.

<u>Aboriginal Impacts</u>

The DFN and Gunn Métis submitted that the project should not be approved, citing its evidence of impacts on traditional land use given in oral testimony. The DFN submitted that the cumulative effects of other resource development within their territory had created significant impacts on traditional land use, and expressed concerns about the impacts of a spill on their lands. The DFN submitted that the AER must take steps to ensure that the project does not take up land in its traditional territory in a manner that would impair the quality or nature of its lands or the ability of those lands to support the meaningful exercise of Treaty rights held by DFN.

Pembina did not respond to DFN's arguments, stating only that Pembina should not be made to compensate or answer for the fact that existing development has negatively affected DFN's ability to exercise its rights closer to its reserve lands. Pembina also submitted that there was no evidence on the record that demonstrated that the impacts to the DFN could not be mitigated.

The DFN requested a number of conditions to the Fox Creek Pipeline, which Pembina substantially committed to provide to the DFN, including advance notice of construction activities, further consultation, and establishing buffer zones around environmentally sensitive areas.

The AER concluded that there may be short-term localized impacts, caused mainly by construction of the Fox Creek Pipeline, which may impair the DFN's ability to carry out traditional practices. The AER concluded that some impacts may be appropriately mitigated, and ordered Pembina to conduct post-construction monitoring of the effectiveness of its reclamation and revegetation methods for the recovery of traditional plant ecosystems.

The AER declined to impose a condition on Pembina to work with a mutually agreed upon ethnobotanist with the Gunn Métis, noting that this would be duplicative of the conditions it already imposed with respect to vegetation management and post-construction monitoring.

<u>Order</u>

In conclusion, the AER held that the Fox Creek Pipeline was needed, that it could be constructed and operated safely, and was environmentally responsible. The AER held that the impacts on landowners and aboriginal peoples could be mitigated to a level consistent with responsible development.

Accordingly, the AER approved the Fox Creek Pipeline on the following conditions:

- Pembina must reduce the permanent ROW on the Nielsen property from 35 meters to a maximum of 25 meters;

- Pembina must install additional block valves to reduce the potential release volumes into the Paddle River;

- Pembina must submit a vegetation management control plan for review within 120 days of the issuance of this decision; and

- Pembina must comply with other conditions as set out by Alberta Environment and Parks related to KWBZs.

ALBERTA UTILITIES COMMISSION

ATCO Gas and Pipelines Ltd. (South) Inland Loop Transmission Pipeline (Decision 21258-D01-2016)
Facilities – Pipeline

ATCO Gas and Pipelines Ltd. (South) ("ATCO") applied for an amendment to its pipeline licence 16723 pursuant to section 11 of the *Pipeline Act* and section 4.1 of the *Gas Utilities Act* for:

- The addition of 18.3 kilometers of 508-millimete outside diameter pipeline; and
- Above ground valve assemblies at the endpoints of the new pipeline,

  (the "Inland Loop Pipeline").

ATCO proposed to build the Inland Loop Pipeline between its existing Norma control station (located at SW-34-053-18 W4M) to its existing Lamont control station (located at SE-5-055-19 W4M). ATCO submitted that the Inland Loop Pipeline would increase capacity on ATCO's existing Inland transmission system, carrying sweet natural gas into the Fort Saskatchewan and Edmonton areas.

ATCO proposed to begin construction for above-ground valve assemblies in June of 2016, and that the total value of the capital addition of the Inland Loop Pipeline would be approximately $388 million, based on its preferred route and configuration.

ATCO noted that it had identified the Inland Loop Pipeline as its next expected capacity expansion project in its 2013/2014 general rate application. ATCO submitted that the Inland Loop would maximize available supply from NOVA Gas Transmission Ltd.'s ("NGTL") North Lateral pipeline, east of Edmonton.

ATCO also noted that it submitted conservation and reclamation ("C&R") application for the Inland Loop Pipeline to the AER in September 2015. The AER approved the C&R application on March 29, 2016.

ATCO submitted that it completed consultation and notification activities in respect of the Inland Loop Pipeline pursuant to AUC Rule 020: *Rules Respecting Gas Utility Pipelines* ("Rule 20"). ATCO submitted that there were no outstanding concerns or objections from stakeholders.

The AUC held that the Inland Loop Pipeline met the requirements of Rule 20 pertaining to public consultation, and noted that there were no outstanding public or industry objections or concerns.

The AUC determined that the Inland Loop Pipeline was required to meet additional system capacity to avoid a natural gas supply shortfall by the winter of 2016-2017 in the Edmonton area. The AUC also noted that the need for the Inland Loop Pipeline was approved in Decision 3577-D01-2016.

The AUC determined that the Inland Loop Pipeline was in the public interest pursuant to section 17 of the *Alberta Utilities Commission Act*. The AUC therefore approved the amendment to ATCO's licence 16723 to construct the Inland Loop Pipeline.

ATCO Gas and Pipelines Ltd. 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast (Decision 20604-D01-2016)
Rates – True-Up – Capital Tracker

ATCO Gas and Pipelines Ltd. ("ATCO") applied for approval of its 2014 capital tracker true-up and 2016-2017 capital tracker forecast under performance-based regulation ("PBR").

The PBR framework, as described by the AUC, provides a formula mechanism for the annual adjustment of rates over a five year term. In general, the companies' rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation ("I Factor") relevant to the prices of inputs less an offset ("X Factor") to reflect productivity improvements that the companies can be expected to achieve during the PBR plan period. The resultant I-X mechanism breaks the linkages of a utility's revenues and costs in a traditional cost-of-service model. The PBR framework allows a company to manage its business with the revenues provided for in the indexing mechanism and is intended to create efficiency incentives similar to those in competitive markets.

However, certain items may be adjusted for necessary capital expenditures ("K Factor"), flow through costs ("Y Factor"), or material exogenous events for which the company has no other reasonable cost control or recovery mechanism in its PBR plan ("Z Factor").

This supplemental funding mechanism was referred to in Decision 2012-237 as a "capital tracker" with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a K Factor adjustment to the annual PBR rate setting formula.

In order to receive capital tracker treatment under PBR, a capital project or program must meet the following three criteria established in Decision 2012-237:

- The project must be outside of the normal course of the company's ongoing operations ("Criterion 1");
- Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party ("Criterion 2"); and
- The project must have a material effect on the company's finances ("Criterion 3").

The AUC had previously approved ATCO's K Factor placeholders on an interim basis in the amount of $13.196 million for ATCO's 2014 PBR rates. The AUC also later approved ATCO's 2015 K Factor placeholders on an interim basis in the amount of $34.95 million for 2015, and directed ATCO to include a K Factor placeholder in its 2016 PBR rates equal to 90 percent of the proposed 2016 K Factor.

In Decisions 3267-D01-2015 and 20385-D01-2015, the AUC finalized ATCO's 2013 K Factor true-up and 2014-2015 forecast applications. In those decisions, the AUC approved actual 2013 K Factor amounts of $6.9 million for the northern service area, and $2.7 million for the southern service area, resulting in a 2013 K Factor true-up refund of $9.4 million. The AUC also approved a 2014 K Factor forecast of $13.1 million in the northern service area and $5.9 million in the southern service area, and a 2015 K Factor forecast of $21.0 million in the northern service area, and $11.4 million in the southern service area on an interim basis, pending future true-ups.

ATCO applied for true-ups of the following 2014 K Factor amounts:

Project or Program	**2014 Interim (North)**	**2014 Interim (South)**	**2014 Variance (North)**	**2014 Variance (South)**
Steel Mains Replacement	5,574	643	(354)	(210)
Plastic Mains Replacement	2,212	3,390	75	(103)
Transmission Driven	814	211	9	(26)
Meter Relocation and Replacement	1,481	128	(309)	(128)
Line Heater Reliability	235	-	(3)	-
Regulating Metering Station Improvements	587	-	(44)	-
New Urban Service Lines	-	222	-	(58)
Service Line Replacements and Improvements	774	1,156	(6)	7
New Regulating Meter Stations	238	-	14	-
Urban Main Improvements	191	-	(191)	-
Urban Main Relocations	1,007	128	(169)	(128)
Total 2014 K Factor Amount	**13,113**	**5,878**	**(977)**	**(645)**

ATCO applied for K Factor treatment for the following projects in 2016 and 2017:

Project or Program	**2016 Forecast (North)**	**2016 Forecast (South)**	**2017 Forecast (North)**	**2017 Forecast (South)**
Steel Mains Replacement	9,723	2,025	12,229	3,186
Plastic Mains Replacement	6,212	8,362	8,335	10,868
Transmission Driven	5,373	3,749	7,522	7,216
Meter Relocation and Replacement	1,374	248	924	-
Line Heater Reliability	920	275	1,297	690
Cathodic Protection	302	199	390	302
Regulating Metering Station Improvements	291	-	339	-

New Urban Service Lines	-	769	-	948
Service Line Replacements and Improvements	1,328	2,144	1,601	2,631
New Regulating Meter Stations	600	217	786	290
Urban Main Extensions	362	-	703	-
Urban Main Improvements	419	174	559	273
Urban Main Relocations	1,664	144	2,136	194
Emergency Supply	-	167	-	165
Total K Factor Amounts	**28,867**	**18,472**	**37,219**	**26,763**

<u>Grouping of Projects</u>

ATCO submitted that it maintained the same project groupings as proposed in its previous capital tracker applications, which were approved in Decision 2013-435 and Decision 3267-D01-2015.

The AUC determined that to the extent the project groupings as applied for are the same as those approved in Decision 2013-435 and Decision 3267-D01-2015, the AUC held that it would not re-evaluate such groupings. The AUC however noted that while it approved the groupings, it also directed that ATCO provided further information in respect of its Regulating Metering Station Improvements, New Regulating Meter Stations, Meter Set Improvements, Meters and Instruments, Regulators and Meter Installations, Urban Main Extensions, and New Urban Service Lines projects. The AUC also requested that ATCO provide an analysis on grouping all metering related projects into a single project.

ATCO explained with respect to the metering projects, that new meter sets are tracked separately from the cost to improve meter sets, because the cost drivers are different. New meters, ATCO submitted, are driven by growth, while improvements are primarily driven by aging assets, replacements and significant changes to customer requirements. ATCO explained that it separated regulating meter and customer meter programs due to the vast difference in cost per unit.

ATCO also explained that it did not group Urban Main Extensions and New Urban Service Lines together, as ATCO considered the nature of the work involved in each project to be significantly different, as service lines are driven by the connection of a single customer, while main lines service all customers.

None of the interveners raised concerns with ATCO's proposed groupings.

The AUC held that ATCO's proposed grouping for each of the metering projects was reasonable, given the differing cost drivers and asset types. The AUC therefore approved the project groupings as filed.

<u>Criterion 1 Assessment</u>

The AUC held that it had previously approved all of ATCO's projects (with the exception of Emergency Supply) in Decision 2013-435 or Decision 3267-D01-2015 as compliant with Criterion 1 on an actual or forecast basis. Accordingly, the AUC held that there was no need to re-assess such projects, as no evidence was presented that would require such a re-assessment.

No objections were raised by any interveners for the following previously approved projects:

- Line Heater Reliability;
- Regulating Metering Station Improvements;
- Service Line Replacements and Improvements;
- Urban Main Improvements; and
- Urban Main Relocations.

Accordingly, as the AUC found that no intervener raised any concerns with the above projects, the scope, level and timing of the forecast costs for 2016-2017 were held to be reasonable, and the AUC approved each project as filed. The AUC also found the actual incurred costs for 2014 were prudent, and accordingly approved such costs as filed.

The remaining previously approved projects were also approved as filed, unless otherwise noted.

The Consumers' Coalition of Alberta ("CCA") and Utilities Consumer Advocate ("UCA") raised objections to the Steel Mains Replacement program, as both argued that ATCO had not provided adequate engineering assessments. The CCA also expressed concerns that ATCO relied on a "demerit point" program to assess risks as part of its Steel Mains Replacement program, but did not provide any information with respect to how the demerit point system affected forecast costs. The CCA also expressed concerns about the frequency and classification of gas leaks on ATCO's system, which the CCA described as unsupported and arbitrary, as the CCA noted that ATCO's evidence did support a finding that gas leaks were becoming more frequent.

The AUC determined that the demerit point system, to the extent that it affects or changes current forecasts for Steel Mains Replacements, must be tested by the AUC in future proceedings. Therefore the AUC directed ATCO to file its proposed revisions to the demerit point system as part of its 2015 capital tracker true-up application.

The AUC held that the late introduction of the CCA's concerns regarding leak rates prevented parties from fully exploring the issues on an evidentiary basis. Therefore the AUC held that there was an insufficient basis to reject the Steel Mains Replacement as proposed by ATCO. However, the AUC determined that such additional data would be helpful in future proceedings, and directed ATCO to provide data on the total number of leaks per 100 kilometers on a 2-year and 10-year time period basis.

The AUC held that the scope, level and timing, of forecast costs in 2016 and 2017 were reasonable. The AUC also held that the actual costs for 2014 were reasonable and prudent.

The AUC approved ATCO's Plastic Mains Replacement project, finding the scope, level and timing of such expenses for 2016 and 2017 to be reasonable. The AUC also approved the 2014 costs as reasonable and prudent. However the AUC raised concerns with respect to ATCO's forecasting regression models for the Plastic Mains Replacement program, noting a number of discrepancies, and some difficulty in reproducing ATCO's regression analysis. Consequently, the AUC directed ATCO to re-estimate its regression equations, and to apply these equations to recalculate its 2016 and 2017 costs. Subject to the directions to update its regression analysis, the AUC approved the continuation of the Plastic Mains replacement.

With respect to Transmission Driven Capital forecast costs, the AUC held that the timing for the Palliser and Bridlewood Gate projects, which form part of the Southwest Calgary Connector, were uncertain due to the the fact that no approvals had been requested for the Southwest Calgary Connector Project. Accordingly, the AUC held that there was insufficient evidence to include the forecasted costs for this project in the 2017 forecast of Transmission Driven Capital.

The AUC directed ATCO to update its forecast costs for the New Urban Service Lines, Urban Main Extensions, and Rural Main Extensions and Service Lines projects using the Q4 Canada Mortgage and Housing Corporation report, on the basis of ATCO's evidence that the forecast costs are highly dependent on larger economic factors. The AUC directed that these forecasts be updated in ATCO's compliance filing to this decision. The AUC therefore deferred any findings on the scope, level and timing of forecast costs for the New Urban Service Lines, Urban Main Extensions, and Rural Main Extensions and Service Lines projects until ATCO filed its compliance filing, including the updated Q4 forecast from the Canada Mortgage and Housing Corporation.

With respect to the Emergency Supply project, ATCO explained that the purpose of the project was to maintain service to customers in the event of an outage on the distribution system by maintaining mobile compressed natural gas units to respond to emergencies. ATCO explained that a number of its existing mobile units are reaching the end of their useful lives, noting that such assets will need to be replaced in 2016 and 2017.

ATCO forecasted total expenses related to Emergency Supply over the forecast period of $0.4 million, split between both north and south service areas.

The CCA submitted that ATCO's mobile unit capacities cannot be used for all loss of supply situations, and are only viable for certain limited flow scenarios. The CCA therefore argued that there was insufficient evidence to show that the Emergency Supply project met the Criterion 1 test for capital tracker treatment.

The AUC held that the expenditures under the Emergency Supply program were of sufficient importance to provide service at adequate levels, and that such service may be compromised if such expenditures were not taken. However, the AUC noted that it was concerned with the scope, level and timing of the expenditures. The AUC held that ATCO had not sufficiently demonstrated that the timing of the expenditures were outside the discretion of management and that current service quality could not be maintained through continuing with operating and maintenance levels of spending. Accordingly, the AUC held that it was not prepared to approve the Emergency Supply project for capital tracker treatment, and directed ATCO to remove amounts associated with the Emergency Supply program from its compliance filing. The AUC noted that ATCO may apply for capital tracker treatment of the Emergency Supply program on an actual basis at the time of the 2016-2017 capital tracker true-up applications.

The AUC held that each of the remaining capital tracker projects and programs met the requirements for Criterion 1 and accordingly approved the need, scope, level and timing for each program, either on an actual basis for 2014, or on a forecast basis for 2016 and 2017.

However, since the AUC directed changes to ATCO's accounting test as it relates to the approved I-X index value and Q Factor values for 2016, the AUC held that it was unable to make a determination as to whether the capital tracker projects met the accounting test under Criterion 1 in its entirety.

The AUC therefore directed ATCO to revise its accounting test in its compliance filing to reflect the approved I-X index value and Q Factor values for 2016 and 2017.

Criterion 2 Assessment

ATCO confirmed that all of the capital tracker projects and programs applied for, both for its 2014 true-up and its 2016-2016 forecast, were previously approved under Criterion 2, and that the cost drivers had not changed since its last application.

With respect to its new capital tracker project, Emergency Supply, ATCO submitted that this project was aimed at asset replacement or refurbishment.

None of the interveners raised any concerns with ATCO's submissions with respect to Criterion 2.

The AUC noted that for the purposes of the 2014 true-up, and 2016-2017 forecast, there was no need to undertake an assessment of whether the previously approved projects complied with Criterion 2, as they were approved in Decision 3267-D01-2015, and the cost drivers had not changed.

The AUC did not assess Emergency Supply against Criterion 2, as it has already rejected this program for capital tracker treatment under Criterion 1.

Criterion 3 Assessment

Criterion 3 is a two step materiality test which assesses the impact of capital tracker costs at four basis points of total revenue requirement for individual projects or programs, and 40 basis points of total revenue requirement for the total capital tracker costs not covered by the I-X mechanism for the applicable year.

For its 2014 capital tracker true-up, ATCO applied a four basis point threshold of $0.147 million for its northern service area, and $0.121 million for its southern service area. ATCO applied a 40 basis point threshold of $1.47 million for its northern service area and $1.21 million for its southern service area, which it submitted were previously approved in Decision 3267-D01-2015. ATCO also submitted that each 2014 capital tracker project or program satisfied both materiality requirements of Criterion 3.

For 2016-2017, ATCO submitted that it calculated the materiality thresholds consistent with the methodology set out in Decision 2013-435. However, since ATCO did not have approved inflation factors for 2016 or 2017, it used the approved 2015 inflation factor of 1.49 percent for both 2016 and 2017. Accordingly, ATCO calculated its 2016 materiality thresholds as follows:

- Four basis point threshold: $0.152 million for its northern service area;
- Four basis point threshold: $0.124 million for its southern service area;
- 40 basis point threshold: $1.52 million for its northern service area; and
- 40 basis point threshold: $1.24 million for its southern service area.

ATCO calculated its 2017 materiality thresholds as follows:

- Four basis point threshold: $0.154 million for its northern service area;
- Four basis point threshold: $0.126 million for its southern service area;
- 40 basis point threshold: $1.54 million for its northern service area; and
- 40 basis point threshold: $1.26 million for its southern service area.

None of the interveners to the proceeding took issue with ATCO's calculations.

The AUC held that ATCO's calculations and forecasting methods were reasonable. The AUC accordingly approved ATCO's 2014 threshold values as filed, and confirmed that the 2014 true-up values met the materiality thresholds of Criterion 3 for capital tracker treatment. However, since the filing of ATCO's application, the AUC provided a final 2016 I-X value of 0.90 percent in Decision 20820-D01-2015. Therefore, the AUC directed ATCO, in its compliance filing, to apply materiality thresholds for Criterion 3 using the approved 2016 I-X factor as a forecast value for both 2016 and 2017.

Order

The AUC approved ATCO's 2014 K Factor adjustments for its northern service area of $977,000, and for its southern service area of $645,000 as final. The AUC directed ATCO to propose, in its compliance filing, how the difference between its interim and final rates would be refunded to its customers.

The AUC also directed ATCO to propose a method to collect the difference between the respective 2016 and 2017 placeholder amounts and the approved 2016 and 2017 K Factor amounts in its compliance filing.

The AUC therefore directed ATCO to file a compliance filing in accordance with the AUC's findings and directions made in this decision on or before May 12, 2016.

ENMAX Energy Corporation 2015-2016 Regulated Rate Option Non-Energy Tariff Application (Decision 20480-D01-2016)
Rates – Regulated Rate Option

ENMAX Energy Corporation ("ENMAX") applied for approval of its 2015 to 2016 regulated rate option ("RRO") non-energy tariff pursuant to section 103 of the *Electric Utilities Act* and the *Regulated Rate Option Regulation*.

ENMAX requested the following amounts for its forecast non-energy revenue requirement in 2015 and 2016:

Item	**2015 forecast ($000)**	**2016 forecast ($000)**
B&CC	10,189	9,671
Shared Service & ENMAX Power Common Costs	2,047	2,052
Operations Costs	1,023	1,060
Other Costs	(554)	(937)
Depreciation	416	416
Amounts included/excluded from other AUC Decisions	(106)	(12)
Non-Energy Margin	783	759
PILOT	260	254
Total	**14,058**	**13,711**

<u>Compliance with previous AUC Directions</u>

In Decision 2014-138, the AUC directed ENMAX to provide information about the billing and customer care ("B&CC") cost allocations, between affiliate companies in its next RRO non-energy tariff application. ENMAX requested confidential treatment of the information it submitted concerning responses to Direction 7 from the AUC arising from Decision 2014-138 with respect to B&CC. ENMAX requested such confidentiality due to the commercially sensitive nature of the information on B&CC costs allocated to its unregulated competitive businesses which from part of the ENMAX group of companies.

The AUC also directed ENMAX, in Decision 2014-138 to file its most recent actuarial valuation, effective December 31, 2012, as part of its next RRO non-energy tariff application. The AUC held that ENMAX filed its most recent actuarial pension valuation with the application, and therefore complied with the direction.

In Decision 2941-D01-2015, the AUC directed ENMAX to provide information concerning its payment in lieu of taxes ("PILOT") filings in its next non-energy application, including an explanation of its reporting of PILOT, and support for its PILOT calculations.

The AUC held that the amounts claimed for PILOT treatment by ENMAX were reasonable. However, since the AUC approved a higher site count retention rate and new inflation rates for test years, the AUC directed that the PILOT calculation be updated to reflect these related findings.

In Decision 2014-347, the AUC directed ENMAX to use the average of its gross margin numbers from audited financial statements for the most recent three years for which gross margin data was available for the purposes of allocating costs.

In Decision 2014-347, the AUC also directed ENMAX to remove any affiliate company financial metrics from its long-term variable pay plan ("LTVPP"), as the AUC did not allow a variable component based on parent company financial performance in the variable pay component of revenue requirement.

ENMAX submitted that it removed $69,000 and $66,000 for 2015 and 2016 respectively from its LTVPP amounts to reflect the AUC's direction in Decision 2014-347.

The AUC held that in ENMAX's initial application, it had misstated the amounts removed, but accepted the updated calculations of $69,000 and $66,000 provided by ENMAX. The AUC therefore directed ENMAX to update the amounts in its compliance filing to this application.

<u>Inflation Factors</u>

ENMAX submitted that it applied the following inflation factors for 2015 and 2016:

Category	2015 forecast	2016 forecast
Management Professional Staff	4.12%	4.0%
Canadian Union of Public Employees (CUPE) Local 38	2.5%	3.5%

ENMAX also submitted that it inflated all other labour costs for 2016 by 4.1 percent, and all other non-labour costs by 2.1 percent, using figures adopted from the Conference Board of Canada and Statistics Canada.

ENMAX stated that its annual salary forecasts were generated from either collective bargaining agreement (in the case of CUPE labour costs) or from survey market data in setting compensation within plus or minus 10 percent of median salary in the competitive market.

The Consumers' Coalition of Alberta ("CCA") questioned the data used by ENMAX, since it predated the recent decline in commodity prices, resulting in overstated inflation rates and noted that more recent Conference Board of Canada forecasts are substantially different from those provided by ENMAX. The CCA accordingly recommended that the AUC reduce ENMAX's requested inflation amounts to at least 2.1 percent for all labour components in 2016 and to 0.0 percent for 2016.

The Utilities Consumer Advocate ("UCA") also supported a reduction to inflation factors, noting that the Spring 2016 Conference Board of Canada report contained drastically different inflation factors and consumer price indices ("CPI") for Alberta. The CCA therefore recommended that the AUC reduce the inflation factors to 1.1 percent for 2016 and 1.75 percent for 2016 based on the average of forecast reports. The CCA also recommended that labour costs be reduced to 1.7 percent for 2016 based on the average of forecast reports.

The AUC held that ENMAX's forecast costs for 2015 used data from 2014, and determined that more recent data which becomes available during the course of a hearing should be used. The AUC therefore found that ENMAX's forecasts based on 2014 data no longer provided an accurate reflection of labour and non-labour increases.

However, the AUC did not agree with the UCA and CCA's recommended interest rates. The AUC held that increases of 1.0 percent for 2015, and 1.7 for 2016 for labour and non-labour salary was reasonable. The AUC accepted the inflation rates for unionized employees as filed. The AUC therefore directed ENMAX to reflect the AUC's findings in its compliance filing.

Site Count Forecast

ENMAX submitted that it generated its site count forecast using a previously approved site count forecast methodology, which it described as exponential smoothing with a trend. ENMAX provided the following site count forecasts to the AUC:

	2014 actual	2014 approved	2015 forecast	2016 forecast
Residential	181,937	185,093	172,800	160,147
Commercial	13,176	13,029	12,027	10,750
Total	195,113	198,122	184,827	170,896

ENMAX submitted that its RRO site reductions have been slowing from previous years, noting that RRO sites fell by more than 30,000 in 2012, whereas RRO sites fell by only 8,000 in 2014. Therefore, ENMAX forecasted residential decreases of 6.0 and 8.5 percent for 2015 and 2016, and commercial decreases of 9.5 percent and 11.7 percent in 2015 and 2016.

The CCA submitted that year over year site count reductions from 2013 and 2014 were 6.4 percent for residential RRO customers and 8.1 percent for commercial customers. The CCA submitted that since ENMAX noted that site count decreases were slowing, the year over year site count decrease should be less than the year over year reductions for 2013 and 2014.

The AUC held that ENMAX's forecast site counts did not accord with its evidence of a trend of lower site count reduction rates. Accordingly, the AUC determined that ENMAX's site count reductions for RRO customers were not reasonable.

The AUC therefore directed ENMAX to change its site count reduction forecast to no more than the 2014 end of year total RRO reduction rates, noting that such data was the most up-to-date information available. Accordingly, the AUC directed ENMAX to restrict its RRO site reduction rate to 4.0 for both 2015 and 2016 in its compliance filing.

Billing and Customer Costs

ENMAX submitted that its B&CC costs were supported through a centralized allocation model, including regulated, competitive and municipal services provided by ENMAX Encompass Inc. ENMAX provided the following cost information for its applied-for B&CC costs:

($000)	2014 actual	2015 forecast	2016 forecast
Customer Care	2,700	2,549	2,443
Billing	2,801	1,447	1,404
All Other B&CC costs	6,135	6,193	5,824

ENMAX noted that the decline in B&CC costs from 2015 to 2016 was primarily driven by the allocation factors, using the number of RRO site relative to non-RRO sites. ENMAX noted that this decline was offset somewhat by inflation.

The AUC held that since it previously directed changes to site counts and inflation rates, which are key elements to the allocation of B&CC costs, ENMAX would be required to update its B&CC costs to reflect the changes ordered to those figures. Accordingly, the AUC directed ENMAX to update its B&CC costs in its compliance filing.

The AUC also held that given ENMAX's representations throughout the proceeding that it was performing further analysis on its B&CC costs, the AUC directed ENMAX to present the results of its B&CC costs analysis as part of its next RRO non-energy tariff application.

Bad Debt

ENMAX submitted that bad debt costs typically fluctuate with economic conditions, volumes and energy prices. ENMAX indicated that it intended to place an increased emphasis on collections in the forecast period, and expected to decrease bad debt costs in 2015 and 2016.

ENMAX forecast the following amounts and percentages for bad debt costs:

($000)	2014 actual	2015 forecast	2016 forecast
Residential	2,459	1,683	1,722
Commercial	178	117	116
Total Bad Debt	2,637	1,800	1,838
Revenue	264,427	218,119	227,825
Bad Debt as % of Revenue	1.00%	0.83%	0.81%

ENMAX identified four risk factors that could negatively affect its RRO bad debt forecast in the test period:

- Amendments to existing legislation;
- Future amendments to legislation, including reconnecting high credit risk customers;
- Adverse economic conditions; and
- Exogenous and unforeseen circumstances outside ENMAX's control.

The AUC approved ENMAX's bad debt forecast, noting that bad debt numbers were based on recent years of actual data, and that lower energy prices may reduce the amount of bad debt. However, since the bad debt forecast costs and revenue assumptions were generated using applied for site count retention rates and an inflation factor of 2.1 percent, the AUC directed ENMAX to update its bad debt forecast using the newly approved site retention rates and inflation factors in its compliance filing.

Working Capital

ENMAX requested approval for working capital amounts related to the lag time for items such as the cost of electricity, grid charges, salaries, B&CC costs, and goods and services tax. ENMAX requested working capital amounts of $(795,000) and $(963,000) for each of 2015 and 2016.

The AUC approved the working capital requirements as filed, subject to any changes resulting from changes to inflation factors and site counts. The AUC directed ENMAX to update its working capital amounts in its compliance filing.

Rent Expense

ENMAX requested approval of rent expenses related to assets held outside of the RRO, that are used to provide RRO service. ENMAX submitted that its rent expense costs were $0.48 million for 2015 and $0.45 million for 2016.

The AUC approved the rent expenses as filed.

Revenue Requirement Offsets

ENMAX requested the following revenue offsets, which are fees collected directly from RRO customers for certain items that offset the costs for utility services provided by the RRO:

($000)	2014 actual	2015 forecast	2016 forecast
Residential	(2,232)	(2,464)	(2,515)
Commercial	(296)	(331)	(338)
Total	**(2,528)**	**(2,795)**	**(2,853)**

ENMAX submitted that its 2015 costs were drawn from its 2015 budget, and its 2016 costs were calculated by escalating its 2015 costs by an inflation factor of 2.1 percent.

The AUC held that ENMAX's revenue requirement offset amounts were reasonable for 2015 and 2016. However, the AUC determined that since it directed higher site count retention rates and new inflation factors, the revenue requirement offsets were approved subject to any changes directed by the AUC. As such, the AUC directed ENMAX to reflect the changes to revenue requirement offsets in its compliance filing.

Hearing Cost Reserve Account

ENMAX requested continued approval of its hearing cost reserve account in the RRO tariff. ENMAX provided the following information with respect to its hearing cost reserve account:

	2014 actual	2015 forecast	2016 forecast
Opening Balance	-	(168,480)	-
Expenses	21,520	180,000	135,000
AUC funding received/requested	190,000	11,520	135,000
Closing balance	(168,480)	-	-

ENMAX submitted that its expected hearing costs were for its 2015-2016 non-energy application and the commencement of its next RRO non-energy application. ENMAX also submitted that it anticipated an increase in hearing costs due to potential changes to the Alberta electricity market from the new provincial government.

The AUC held that it approved of the continued use of the hearing cost reserve account, and found that ENMAX's forecasts adequately reflected a design meant to achieve a zero balance at the end of the test period.

Non-Energy Risk Compensation

ENMAX proposed to collect a reasonable return through its energy charge once the AUC renders its decision on ENMAX's proposed new energy price setting plan. However, ENMAX noted that until such time as a new energy price setting plan is approved, it proposed to continue to collect a six percent margin through its non-energy rates.

ENMAX submitted that the AUC's determination in Decision 2941-D01-2015 that the reasonable return for RRO rates should be collected through the energy charge only would apply here, but that it was not reasonable to assume that the risk margin constitutes only a return. ENMAX submitted that the six percent margin included both return and risk margin. Accordingly, ENMAX submitted that according to section 6(1)(b)(ii) of the *Regulated Rate Option Regulation*, a separate risk margin must be approved for its non-energy operations going forward.

ENMAX provided an expert report that recommended a non-energy risk compensation margin of between 4.52 percent and 4.64 percent. ENMAX proposed to collect its non-energy margin as the midpoint of this range, at 4.58 percent. ENMAX's expert report used the 6.0 percent margin as a starting point, and backed out the portion of the margin related to a fair return, leaving only the risk compensation component.

ENMAX's expert report used the following steps to determine the non-energy compensation margin:

- Identify the AUC approved return on equity range;
- Adjust the generic return on equity by amending the risk-free rate, accounting for ENMAX's shorter asset lives for RRO service;
- Adjusting the current non-energy return of 6.0 percent by the difference calculated in a similar report generated in 2013;
- Identifying the appropriate risk-free rate for 2015-2016; and
- Determining the risk compensation range by deducting the risk-free rate from the adjusted total non-energy return.

ENMAX's expert justified the use of the AUC approved return on equity in noting that ENMAX has to set aside working capital to support non-energy operations, and that the nature of the RRO business does not lend itself to debt financing despite its obligation to serve.

The UCA submitted that ENMAX's submission on non-energy compensation was not reasonable, and provided no evidence supporting any dollar amount of compensation for risks associated with intra-site variation and bad debt expenses for ENMAX. The UCA therefore recommended non-energy risk compensation of $0.00.

The AUC agreed with the UCA that ENMAX's approach to non-energy risk compensation was not reasonable for an RRO provider. The AUC determined that the generic cost of capital return on equity are calculated for large utilities with significant amounts of invested capital. Therefore the AUC determined that the comparison to generic cost of capital rates by ENMAX was not warranted. The AUC noted in particular ENMAX's reasoning for using generic cost of capital returns would actually result in a further credit to consumers, since the working capital applied for by ENMAX in this proceeding was actually negative, at $(795,000) and $(963,000) for each of 2015 and 2016. Therefore, contrary to ENMAX's assertion that it has to set aside working capital to support its non-energy operations, the non-energy operations for ENMAX's RRO provides working capital to ENMAX.

The AUC also rejected ENMAX's assertion that the risk margin was a mixture of risk and return components, citing a response from ENMAX provided in Proceeding 20480, where it submitted that the RRT non-energy amounts were only for a reasonable return, and were not related to risk.

However, the AUC considered that ENMAX should be able to attempt to quantify the risk associated with bad debts and attrition, noting that EPCOR had previously done so for its non-energy RRO applications. Despite this, the AUC determined that ENMAX had not met its onus to include a non-energy risk compensation amount for the 2015-2016 test years. Accordingly, the AUC directed ENMAX to remove any non-energy risk compensation amounts from its compliance filing.

The AUC did, however, approve the collection of part of the reasonable return amounts approved in Decision 2941-D01-2015 through the non-energy tariff, as ENMAX noted it was seeking to transition the reasonable return from its non-energy RRO tariff to the energy component of its RRO tariff.

Order

The AUC therefore directed ENMAX to re-file its 2015-2016 RRO tariff to reflect the AUC's findings in this decision, and to do so on or before May 30, 2016.

ATCO Pipelines 2016 Interim Revenue Requirement (Decision 21328-D01-2016)
Interim Rates – Revenue Requirement

ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. ("ATCO") applied for approval of a monthly fixed fee of $19,021,720 on an interim basis, representing 60 percent of its forecast revenue requirement increase for 2016, to be effective April 1, 2016. ATCO submitted that the proposed increase was an increase of $22.4 million per annum from the approved 2015 interim revenue requirement, or an increase of 11 percent.

ATCO's 2015-2016 general rate application ("GRA") requested approval of forecast revenue requirements of $208,940,000 for 2015 and $238,844,000 for 2016. In Decision 3577-D01-2016 the AUC held that ATCO was required to submit a compliance filing.

ATCO updated its requested interim revenue requirement amount, submitting that due to scheduling delays its requested effective date of April 1, 2016 was no longer feasible. ATCO requested that it be granted an interim revenue requirement of $239,023,000, equivalent to its 2016 applied-for revenue requirement in its compliance filing, or $19,918,563. ATCO submitted that its request was reasonable and would minimize rate shock, given the shorter time period.

The AUC determined that the requested increase in the interim revenue requirement was material, and would allow ATCO to continue its operations without negative impacts on the safety or reliability of service to customers pending the outcome of its GRA.

The AUC approved ATCO's requested interim revenue requirement of $19,918,563 per month on an interim refundable basis. The AUC found that the monthly amount was prepared using the most up to date information, and noting that the monthly amount would not fully recover ATCO's anticipated annualized shortfall of $33.1 million. The AUC, noted that the monthly amount was set on an interim basis at $17,157,800 for the first four months of 2016.

The AUC approved the monthly interim revenue requirement of $19,918,583 on an interim refundable basis, effective May 1, 2016.

Decision on Review Application of the Métis Nation of Alberta of the Standing Ruling for the Fort McMurray West 500-kV Transmission Project (Decision 21030-D01-2016)
Review Application – Facilities – Standing

The Métis Nation of Alberta ("Métis") filed an application pursuant to Rule 016: *Review of Commission Decisions* ("Rule 16") with the AUC seeking a review of the AUC's ruling which denied the Métis standing in Proceeding 21030, an application by Alberta PowerLine L.P. ("Alberta Powerline") to construct the Fort McMurray West 500-kV Transmission Project (the "Project") from the Wabamun area to the Fort McMurray area.

Alberta Powerline identified a preferred western route, and an alternate eastern route for the Project. Both routes as applied-for seek a 60 meter right-of-way to accommodate conductor swing under heavy wind conditions.

The Métis originally filed a statement of intent to participate ("SIP") noting its concerns with the cumulative effects of the Project on northern wetlands and ecosystems, and the impacts on individual Métis members who exercise aboriginal rights along the length of the Project.

The AUC held that insufficient information was provided in the Métis SIP, and requested further information in respect of whether members of Métis were exercising rights on the land where the Project would be located. The Métis did not respond to this request, but later filed a letter requesting an extension on the time to file such information.

The AUC denied standing to the Métis, holding that while the Métis had met the first branch of the standing test, requiring that an individual demonstrate a legal right, the second branch of the test was not met. The second branch of the standing test generally requires that those seeking standing must file specific information related to the rights asserted, and demonstrate a degree of connection or proximity to the project in question. Accordingly the AUC found that the Métis did not demonstrate that the Project, if approved, may directly and adversely affect the exercise of the rights asserted by the Métis, and denied them standing.

The Métis, as part of its review application, did not take issue with the standing test as applied by the AUC, but submitted that there were new, previously unavailable facts that were not placed before the AUC, which may lead the AUC to materially vary its decision on standing.

The Métis submitted affidavits of four individuals who self-identified as rights-bearing Métis in the area through which the Project would pass, and provided evidence of traditional activities such as hunting, fishing, gathering and camping in the area near the Project right-of-way. The individuals expressed concerns about the potential impacts of the Project on their continued ability to exercise such rights, noting the cumulative impacts of the Project and other industrial development in the area. The Métis submitted that the affidavits demonstrated that the individuals, and by extension the Métis, demonstrated a connection between the proposed Project and the rights asserted.

The Métis also submitted that they were not aware of the Project in sufficient time to prepare the above evidence, and noted that it was not familiar with the AUC's e-filing system.

Alberta Powerline did not take a position on the review application, but noted that it had provided notice to the regional councils of the Métis.

The AUC considered that prior to deciding on the merits of the Métis application, it must as a preliminary matter decide whether to grant leave to file the review application under section 3 of Rule 16, since the Métis was not a party to the proceeding. The AUC exercised its discretion to grant leave to the Métis to review the standing decision.

However, the AUC was not satisfied that the information in the affidavits could not have been discovered or provided before the standing ruling was issued, since the Métis were aware of the application by filing a SIP. Therefore, the AUC held that the Métis had not demonstrated that there were unique circumstances or new facts that would militate in favour of granting a review application. Accordingly, the AUC determined that the Métis had not met the review test set out in section 6(3)(b) of Rule 16, and therefore dismissed the review application.

Although the AUC affirmed its decision denying standing to the Métis, it considered that Métis Local #2010, Métis Local #2002, Métis Local #1909 and Métis Local #2907 (of which each of the individuals that provided affidavits were members) had standing to participate in Proceeding 21030, on the basis that at least one member of each Local exercises his or her aboriginal rights on or in close proximity to the right-of-way of the proposed transmission line routes for the Project.

EPCOR Distribution & Transmission Inc. 2015-2017 Transmission Facility Owner Tariff and 2013 Generic Cost of Capital Compliance Application (Decision 21229-D01-2016)
Compliance Filing – Tariff – Rates – Generic Cost of Capital

EPCOR Distribution & Transmission Inc. ("EDTI") filed an application in compliance with directions made by the AUC in Decision 3539-D01-2015 in respect of EDTI's transmission facility owner ("TFO") tariff, and Decision 20692-D01-2015 in respect of its 2013 generic cost of capital ("GCOC") refiling.

EDTI requested the approval of its 2015-2017 TFO revenue requirement, rates, and its TFO terms and conditions. EDTI also requested true-ups to the years 2013 and 2014 related to the AUC's findings in the GCOC decision. EDTI further requested approval of true-ups for 2015 related to the difference between its interim and approved rates for its TFO tariff and the GCOC decision.

EDTI proposed to aggregate all of the requested true-ups into one net payment of $0.54 million to account for the shortfall over the true-up period, to be added to EDTI's July 2016 TFO rate.

EDTI's adjusted revenue requirements for 2015-2017 were as follows:

- $93,867,300 for 2015;
- $99,816,130 for 2016; and
- $98,591,311 for 2017.

The AUC noted that with respect to each of the directions made in Decision 3539-D01-2015 and 20692-D01-2015, that EDTI had complied with each of the 49 directions made, or that the directions were applicable only to future applications, unless otherwise specified.

The AUC, in Decision 3539-D01-2015 directed EDTI to incorporate the use of a three year average using 2012-2014 actuals to determine forecast revenue requirement amounts related to transmission work for others.

EDTI submitted that it applied a three-year average using 2012-2014 for its 2015-2017 forecast expenses for transmission work for others, which were then increased by an approved overhead factor of 69 percent for direct labour costs, and a cost recovery surcharge of 20 percent.

EDTI submitted that it applied a refined method by calculating each year's costs in 2014 dollars and taking the simple average of the result to calculate the three-year average, as opposed to a simple average. EDTI noted that this approach was previously approved by the AUC in Decision 2012-272. EDTI submitted that the total revenue requirement impact was a reduction of $0.03 million in each of the three years.

The AUC held that EDTI had complied with the AUC's direction in Decision 3539-D01-2015, despite not using the simple average of 2012-2014 costs. The AUC determined that EDTI's refined methodology adequately accounted for inflation escalation, and noted that this approach was previously approved.

The AUC held that since EDTI had complied with all prior directions in Decision 3539-D01-2015 and Decision 20692-D01-2015, that the requested forecast TFO revenue requirements for 2015-2017 were approved, and the requested 2013, 2014 and 2015 true-up refund amounts were also approved.

The AUC accordingly ordered that EDTI's TFO revenue requirements of $93,867,000 for 2015, $99,816,130 for 2016, and $98,591,311 for 2017 were approved as filed. The AUC also approved EDTI's TFO rates and terms and conditions over the same period, as filed.

NATIONAL ENERGY BOARD

Letter and Order TG-001-2016 – NOVA Gas Transmission Ltd. 2016 and 2017 Revenue Requirement Settlement Application (April 7, 2016)

Revenue Requirement – Settlement – Rates

NOVA Gas Transmission Ltd. ("NGTL") applied to the NEB requesting an order approving a settlement establishing NGTL's revenue requirement for 2016 and 2017.

NGTL submitted that the application was supported by the unopposed resolution T2015-02 of NGTL's Tolls, Tariff, Facilities and Procedures Committee ("TTFP").

As part of its application, NGTL also requested an exemption from filing quarterly surveillance reports under section 4 of the *Toll Information Regulations.*

The application was supported by the Canadian Association of Petroleum Producers ("CAPP") and the Industrial Gas Consumers Association of Alberta ("IGCAA"). Centra Gas Manitoba ("Centra") and the Western Export Group ("WEG") had various concerns with the application but did not contest it. Centra was concerned about the rushed process of settlement negotiations, and noted that NGTL shippers may be assuming unknown risk from the flow-through treatment of severance costs which were not quantified.

WEG expressed concerns with NGTL's settlement, including the TTFP reporting requirements, treatment of severance costs, and NGTL's capital cost reporting to the TTFP. WEG was concerned that NGTL's reporting requirements were inadequate, and would not allow WEG to properly monitor NGTL's cost control performance during the term of the settlement. WEG also noted that NGTL was in the midst of a major facilities expansion program, and that NGTL's current reporting commitments would not allow WEG to monitor the continued prudence of NGTL's capital costs.

The NEB determined that WEG raised valid concerns. The NEB noted that since coming under federal jurisdiction, NGTL's revenue requirement has risen from $1.145 billion in 2009 to $1.857 billion in 2016, while NGTL's last depreciation study will be five years old by the end of the settlement.

Given the significant changes to the usage of the NGTL system since coming under federal jurisdiction, the NEB determined that setting an appropriate depreciation rate was critical to ensuring that short and long term costs are just and reasonable. Therefore, the NEB directed that NGTL's 2018 tolls application be supported by a depreciation study, and directed NGTL to file such a depreciation study no later than July 31, 2017 to inform future revenue requirement negotiations.

The NEB denied NGTL's request to be exempt from its obligation to file quarterly surveillance reports, holding that NGTL did not sufficiently justify its request, noting the NEB's determination that more information will help shippers monitor NGTL's results.

The NEB, in denying NGTL's exemption request, found that additional information on NGTL's capital program was required. The NEB determined that additional information should be provided in advance of commencing settlement negotiations for 2018 tolls, noting that having such information on the public record will increase transparency for interested parties, and provide the NEB with an opportunity to clarify areas of concern.

Accordingly, the NEB directed NGTL to file supplemental financial information as provided in supplemental schedules 1.0-9.0 in Section 2G(i) of the settlement, on its capital program for 2016 and 2017 as follows:

- Provide financial information no later than March 31 2017 (for 2016 actuals) and March 31, 2018 (for 2017 actuals); and
- Bridge year information by July 31, 2017 to inform future revenue requirement negotiations.

The NEB also recommended that NGTL report on key capital cost parameters on an annual basis at a minimum, in addition to the information it provides in its facility status update reports. The NEB noted that the level of detail it expected would include a variance of forecast costs included in facilities applications, and the actual costs, and that such analysis would be commensurate with the magnitude of the variance.

The NEB held that the settlement would result in just and reasonable tolls, and therefore approved the settlement. However the NEB cautioned that approval of the settlement was not to be considered an approval of the manner in which the elements of the revenue requirement were determined.

NEB Releases Preliminary Timeline for Energy East (April 26, 2016)
Facilities – Pipeline – Process

The NEB announced the release of a preliminary schedule and timeline to hear the application of Energy East Pipeline Ltd. ("Energy East") for a 4,500 km crude oil pipeline system running from Alberta to New Brunswick (the "Energy East Project").

The NEB noted that the timeframe is reflective of a time limit of 21 months for the process, as directed by the Minister of Natural Resources. The NEB noted that hearings are typically conducted on a 15 month timeframe.

The NEB set out its preliminary schedule for the Energy East Project hearing as follows:

Expected Process Step	Expected Timing
Filing of Consolidated Application by Energy East	Mid-May 2016
Issuance of List of Participants	Early June 2016
Issuance of Hearing Order (including completeness determination)	Mid-June 2016
Panel Sessions in communities along the pipeline route	August- December 2016
Written Process for Participants	January – May 2017
Draft Conditions for Comment	Mid 2017
Final Argument	November – December 2017
NEB Report to Governor in Council	March 2018

The NEB noted that it had not yet determined whether Energy East's application was complete, and that the preliminary schedule was subject to further change, as no formal process decisions have been taken concerning the Energy East Project hearing.

NEB Releases Confidential Disclosure (Whistleblower) Process
Disclosure – Compliance - Whistleblower

The NEB announced the creation of the Confidential Disclosure (Whistleblower) Procedure ("Whistleblower Procedure") on its website. The NEB noted that the Whistleblower Procedure will provide the NEB with a formalized way to receive, track and handle confidential disclosures related to activities at NEB regulated facilities, in light of increased reports over the last two years.

The NEB noted that the Whistleblower Procedure is an anonymous reporting tool for confidential communication with tipsters.

A full text copy of the Whistleblower Procedure can be located here, on the NEB Website.

The NEB's contact form for the Whistleblower Procedure can also be found here, but the NEB notes that whistleblowers may contact the NEB by mail, phone, or email.