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REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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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:

ALBERTA COURT OF APPEAL

ATCO Power Ltd v Alberta Utilities Commission, 2015 ABCA 405
Leave to Appeal - Dismissed

ATCO Power Ltd. ("ATCO") applied to the Alberta Court of Appeal ("ABCA") for leave to appeal AUC, Decision 2014-242 regarding the Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, on the question of whether the AUC erred in law or jurisdiction by failing to consider the impact of obligations imposed by ISO *Rule 203.1* in determining whether the proposed Tariff is discriminatory.

ATCO submitted that the discriminatory effect of the ISO Tariff treated supply transmission service ("Rate STS") customers the same as import opportunity service ("Rate IOS") customers. ATCO submitted that the ISO Tariff failed to reflect the fact that under ISO Rule 203.1, Rate IOS customers can choose whether to offer energy onto the Alberta Interconnected Electric System ("AIES") at any given time, whereas Rate STS customers are obligated to commit their physical generating capacity onto the AIES.

ATCO argued that, given the significant and material difference between the obligations of Rate IOS and Rate STS customers in ISO Rule 203.1, the ISO Tariff was not just and reasonable pursuant to section 121 of the *Electric Utilities Act*.

The AUC submitted that the appeal itself was not *prima facie* meritorious, since it did consider the operational impacts of capacity offer obligations in ISO Rule 203.1 in determining whether the Rate IOS and Rate STS rates were discriminatory.

The ABCA noted that appeals are permitted from decisions of the AUC only on points of law or jurisdiction, pursuant to section 29 of the *Alberta Utilities Commission Act*. The ABCA held that ATCO must raise a "serious, arguable point" to be successful on its application for leave to appeal.

The ABCA reviewed the AUC's findings from Decision 2014-242 and held that the AUC determined that Rate IOS and Rate STS were not unjustly discriminatory as part of the AUC's rate approval function, and was persuaded by other evidence that differences between the two rates justified the treatment imposed. The ABCA characterized the AUC's findings as involving its ratemaking authority at the core of its mandate and expertise. Therefore the ABCA determined that a high degree of deference was warranted.

The ABCA noted that the AUC rejected ATCO's submissions and found no basis to conclude that the treatment for Rate IOS costumers was discriminatory or unjust. The ABCA further noted that the AUC rejected ATCO's submissions on the basis that the ISO Tariff proceeding was not the forum under which to address operational requirements of an ISO Rule.

As a result, the ABCA concluded that the question on appeal was a question of mixed fact and law. Absent any extricable legal error by the AUC, the ABCA found that such questions were expressly precluded from appellate review. The ABCA reiterated that, in order for ATCO to succeed on leave to appeal, it must demonstrate that it has a meritorious argument on the law. Given the high degree of deference given, the ABCA held that the AUC's findings in Decision 2014-242 were within a range of possible, acceptable outcomes that were defensible in respect of the facts and the law.

Accordingly, the ABCA held that since ATCO did not demonstrate a serious, arguable point, the application for leave to appeal was dismissed.

Application of ENMAX Energy Corporation for Permission to Appeal AUC Proceeding 790, Decision 790-D03-2015 (File No. 1501-0315 AC)
Application for Permission to Appeal

ENMAX Energy Corporation ("ENMAX") filed an application for permission to appeal AUC Decision 790-D03-2015.[1]

In its application, ENMAX seeks the following orders from the Alberta Court of Appeal ("ABCA"):

(a) Permission to appeal from Decision 790-D03-2015, in respect of Module "B" of AUC Proceeding 790;

(b) Abridging the time for service of the application, and extending the time for bringing the application;

(c) Adjourning the application *sine die* (i.e. without any fixed date) to be heard at the conclusion of Module "C" of AUC Proceeding 790, in accordance with the reasons in *Capital Power Corporation v Alberta (Utilities Commission)* or in the alternative, to a fixed date; and

(d) Such further and other relief that the ABCA may grant;

(collectively, the "Application").

[1] A summary of the AUC's findings in Decision 790-D03-2015 can be found in the November 2015 issue of this Energy Regulatory Report.

The Application itself was filed to preserve time pursuant to paragraph 5(b) of the *Consolidated Practice Directions of the Court of Appeal of Alberta*.

The grounds upon which ENMAX submitted the Application alleged that the AUC committed the following errors of law or jurisdiction:

(a) Finding that an Incremental Loss Factor ("ILF") methodology for calculating raw loss factors, as proposed by the Alberta Electric System Operator ("AESO") and as amended by the AUC, complies with the *Electric Utilities Act* ("*EUA*") and the *Transmission Regulation* ("*T-Reg*");

(b) Approving its own amendment to the ILF methodology, which was not proposed by any party and in respect of which no party was given the opportunity to make submissions;

(c) Finding that the superposition methodology proposed by ENMAX for calculating loss factors did not comply with the *EUA* and the *T-Reg*; and

(d) Misinterpreting the requirements in the *T-Reg* applicable to transmission line losses and the rules regarding transmission line losses that the AESO is required to make.

A hearing on the Application is currently set for June 21, 2016 in the ABCA.

ALBERTA ENERGY REGULATOR

Confirmation of the Transfer of Pipeline Records to Be Added to the Licence Transfer Application (Bulletin 2015-34)
Bulletin – Licence Transfer Application

The AER announced that it was amending its pipeline licence transfer application process to include a written confirmation that records required by CSA Z662: Oil and Gas Pipeline Systems ("CSA Z662") and part 4 of the *Pipeline Rules* have been maintained by the seller (or transferor) and have been transferred to the purchaser (or transferee) of the licence.

As a result, the following two statements will be added to the licence transfer application in the Digital Data Submission system, and must be agreed to by the transferor and transferee before the AER will process an application to transfer a pipeline licence:

(a) Transferor statement: The transferor hereby confirms that it has collected and retained all records required under the *Pipeline Rules* and CSA Z662. The transferor confirms that it has provided these records to the transferee by the effective date of the licence transfer; and

(b) Transferee statement: The transferee hereby confirms that it has received all records required to be collected and retained under the *Pipeline Rules* and CSA Z662 from the transferor. The transferee is responsible for producing these records on request by the AER. Failure to do so constitutes a noncompliance of AER requirements.

While the above statements are new, the AER reiterated that these statements did not impose any new or additional requirements, as these are already requirements under CSA Z662 and the *Pipeline Rules*. The confirmations are simply a tool for the AER to ensure that the records are transferred prior to the processing and approval of a licence transfer application.

ALBERTA UTILITIES COMMISSION

Alberta Electric System Operator 2016 Balancing Pool Consumer Allocation Rider F (Decision 21031-D01-2015)
Balancing Pool Consumer Allocation – Rider F

The Alberta Electric System Operator ("AESO") applied to the AUC pursuant to section 82 of the *Electric Utilities Act* ("*EUA*") for approval of a $3.25 per megawatt hour ("MWh") credit to all demand transmission service ("DTS") and demand opportunity service ("DOS") market participants, (excluding the City of Medicine Hat and BC Hydro at Fort Nelson) for metered energy from January 1, 2016 to December 31, 2016 ("Rider F"). The AESO stated that all substantive aspects of Rider F continue unchanged from the previously approved Rider F.

Under section 82 of the *EUA*, the Balancing Pool must provide a notice to the AESO of an annualized amount to be refunded to, or collected from, market participants over the course of a year. The Balancing Pool, on November 17, 2015 provided a notice to the AESO that it determined an annualized amount of $204,584,250 for 2016. As provided for by sections 82(5) and 82(6) of the *EUA*, the AESO must include the annualized amount in the ISO tariff.

The AUC noted that no objections were received to the continuation of the AESO's methodology for applying Rider F. The AUC also noted that it must approve, either with or without modification, the allocation of the annualized amount.

The AUC also held that, according to section 82(6)(a) of the *EUA*, it must approve the annualized amount without modification.

Accordingly, the AUC ordered that:

(a) The annualized amount of $204,584,250 provided to the AESO by the Balancing Pool was approved for 2016; and

(b) The proposed Rider F credit of $3.25 per MWh was approved effective January 1, 2016 to December 31, 2016.

AltaGas Pipeline Partnership Preferential Sharing of Records between AltaGas Pipeline Partnership and URICA Energy Real Time Ltd. (Decision 20837–D01-2015)
Preferential Sharing of Records

AltaGas Pipeline Partnership ("AltaGas") applied to the AUC pursuant to section 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*") to permit the sharing of records not available to the public between AltaGas and URICA Energy Real Time Ltd. ("URICA"). AltaGas stated that the purpose of the application was as a result of its negotiations with TransCanada Energy Ltd. ("TCE") to purchase 100 percent of TCE's interest in the Sundance Unit B3 Power Purchase Arrangement ("PPA") in exchange for AltaGas' 100 percent interest in the Sundance Unit B4 PPA being transferred to TCE. Upon the completion of this transaction, AltaGas submitted that it planned to engage the services of URICA to provide dispatch services related to Sundance Unit B3 on behalf of AltaGas.

AltaGas submitted that the records to be provided to URICA included price and quantity offers related to the available output of Sundance Unit B3, but that URICA would have no involvement in any matters related to offer strategy, which will be solely determined by AltaGas.

The Market Surveillance Administrator ("MSA") advised the AUC that it supported the application.

The AUC, in providing its findings on the application, stated that Section 5(5) of the *FEOC Regulation* prohibits a market participant from holding offer control in excess of 30 percent of the total capability of generating units in Alberta.

AltaGas submitted that it would have well below the 30 percent limit, with 2.66 percent offer control of the energy market if the AUC approves the application, while URICA and its associates represented 0.44 percent offer control of the energy market and 14.57 percent of operating reserves market.

The AUC held that based on the information provided in the application, the offer control held by AltaGas would not exceed the 30 percent maximum. The AUC determined that no confidential information would be shared between AltaGas and URICA for the purposes of price-fixing, price-manipulation or any other prohibited conduct under the *FEOC Regulation*.

Accordingly, the AUC issued an order permitting the sharing of records between AltaGas and URICA for the Sundance Unit B3 PPA, effective December 4, 2015 to December 31, 2020, or until the termination of the agreement between AltaGas and URICA, whichever expires sooner.

AltaGas Utilities Inc. Rule 004 Alberta Tariff Billing Code Exemption (Decision 20428-D01-2015)
Rule 004 Exemption

AltaGas Utilities Inc. ("AltaGas") requested exemptions from certain requirements of Rule 004: *Alberta Tariff Billing Code* ("*Rule 004*"), which defines the business processes and mechanics of how bill-ready information is to be produced and transmitted to retailers by electricity and natural gas distributors in Alberta.

AltaGas applied for the following exemptions of *Rule 004* from December 5, 2015, to December 31, 2018:

(a) Section 3.2, Table 3-1, lines (Ref IDs) 14 and 15;

(b) Section 4.3.1(4);

(c) Section 5.4.1(1); and

(d) Section 5.4.1(2).

AltaGas had previously applied for a permanent exemption from *Rule 004*, which was denied by the AUC in Decision 2008-084. In that decision, the AUC directed AltaGas to proceed with preparing a compliance plan to achieve full compliance with *Rule 004*. In response, AltaGas filed a compliance plan on May 28, 2010, which the AUC approved by letter, granting temporary exemptions from the same requirements as AltaGas requested in this application.

AltaGas stated that while it plans to achieve full compliance, it noted that the vendor of its customer billing software was not available to implement an updated version of its software, and that the cost of doing so was prohibitive. As a result, in AltaGas' submission, it made the internal decision to continue utilizing its current billing system in conjunction with the continuation of its requested *Rule 004* exemptions.

AltaGas stated that its replacement billing system, which will address the non-compliance issues, is currently scheduled for implementation in 2019.

AltaGas submitted that it is continuing to seek the temporary exemption from Ref ID 14 in Table 3-1 of *Rule 004*, since, when a rider rate change occurs in a single billing period, its current customer billing system is not capable of applying the different rates within the same period. However, AltaGas noted that only non-energy based charges like franchise fees and property tax rate riders cannot be split within a month, so the non-compliance does not result in any errors on billings.

With respect to Ref ID 15 of Table 3-1, AltaGas submitted that it is requesting an exemption as its current billing system is not able to split energy usage when an RRT change occurs. However, AltaGas clarified that this inability exists only when a site is idle or de-energized, therefore energized sites with billed usage will have their charges billed correctly.

A number of retailers expressed concern that they are required to incur man-hour costs to manually correct these non-compliances, and deal with elevated numbers of customer complaints as a result.

AltaGas reiterated that a continuation of the exemptions is reasonable pending the implementation of its long-term solution. AltaGas submitted that the exemptions strike a reasonable balance between distributors, retailers and end use customers and will avoid costly temporary fixes.

With respect to cancellations and rebills, AltaGas submitted that its billing system was unable to complete a one-step cancel and rebill that affects more than one billing period. AltaGas stated that it has had a workaround in place on its system since 2010 to accommodate such cancellations and rebills. AltaGas noted that the overall incidence of such cancel and rebill events are quite low, affecting 0.0985 percent of retail sites billed annually.

Several retailers that intervened in the proceeding commented that the current workaround results in the timing risk and cash flow recovery of such rebills falling to retailers and end-use consumers. Interveners submitted that approximately 200 hours per year are incurred by accommodating AltaGas' workaround, composed of 80 hours of training, 100 hours for dealing with billing exception, and 20 hours participating in the associated regulatory process. Others submitted that the workaround process introduces the risk of further error into the billing process.

AltaGas replied to these concerns, submitting that it plans to become fully compliant, but stressed the need to balance temporary non-compliance costs with the cost of expedited compliance.

The AUC held that full compliance with *Rule 004* was important to ensure an open, fair and effective retail market. However, the AUC noted that some circumstances warrant temporary exemptions pursuant to section 6.1.5 of *Rule 004*, which expressly allows temporary exemptions.

The AUC held that the impacts of AltaGas' non-compliance with the provisions of *Rule 004* for which AltaGas requested exemptions was manageable. The AUC further held that granting AltaGas' requested exemptions did not affect AltaGas' obligation to comply with the *Regulated Default Supply Regulation*, and therefore found that granting the temporary exemptions was in the public interest.

However, with respect to the requested exemption from section 5.4.1(2) related to cancellations and rebillings, the AUC held that this exemption would have a greater impact on retailers and end-use consumers in AltaGas' service territory. The AUC held that since the proposed workaround would affect a small number of customers, and that no viable alternatives were presented, it approved the requested temporary exemption from section 5.4.1(2) of *Rule 004*.

The AUC stressed that it remained concerned about AltaGas' repeated applications for temporary exemptions from *Rule 004*, extending over a decade. However, given AltaGas' evidence related to the costs of implementing a temporary solution, the AUC approved the requested exemptions.

The AUC noted that it was approving AltaGas' temporary exemptions in reliance on AltaGas' proposed compliance timeline. Therefore the AUC directed AltaGas to advise the AUC on an annual basis whether the proposed compliance timeline is still correct, and to advise of any measures taken to address schedule slippage.

AltaGas' compliance timeline indicated that it would achieve full compliance with *Rule 004* in 2019, but did not provide a specific date. Noting the numerous prior applications for temporary exemptions, the AUC held that based on the evidence before it, it expected a date no later than June 30, 2019, but imposed a deadline of December 31, 2018 in order to avoid the regulatory burden of a further temporary exemption application. The AUC therefore directed AltaGas to refile its compliance timeline to reflect this decision.

Accordingly, the AUC ordered that:

(a) AltaGas be granted a temporary exemption from the requirements of Section 3.2, Table 3-1, Ref IDs 14 and 15; Section 4.3.1(4), Section 5.4.1(1) and Section 5.4.1(2) of *Rule 004* effective from the date of the decision until December 31, 2018;

(b) AltaGas be directed to monitor and provide annual reports simultaneously with its Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors* annual report:

   (i) Whether its compliance timeline is still correct, and if not, what measures AltaGas has undertaken to prevent schedule slippage;

   (ii) The number of non-compliances for the approved exemptions on a quarterly basis; and

   (iii) Concerns raised by retailers or any possible customer dissatisfaction as a result of the exemptions and any mitigation measures taken in response; and

(c) AltaGas be directed to file an updated compliance plan within 30 days of this decision.

ENMAX Power Corporation 2016 Interim Transmission Tariff (Decision 21017-D01-2015)
Interim Transmission Tariff

ENMAX Power Corporation ("ENMAX") applied for approval of its 2016 interim transmission tariff by continuing its 2015 transmission tariff on an interim refundable basis, effective January 1, 2016 until such time as the AUC approves a revised interim or final 2016 transmission tariff.

ENMAX submitted that the AUC approved its 2015 transmission tariff in Decision 2014-347 and in Decision 20124-D01-2015, and that its 2015 transmission tariff was set to expire on December 31, 2015. ENMAX submitted that it intended to file a transmission tariff for 2016 and 2017 with the AUC in 2016. The AUC also issued Decision 20819-D01-2015 which varied paragraphs 34 and 35 of Decision 20124-D01-2015.

The AUC approved ENMAX's request to continue with its 2015 transmission tariff on an interim and refundable basis. The AUC directed ENMAX to use the revised revenue requirements and resulting 2015 transmission tariff that was approved in Decision 20819-D01-2015 for the purposes of calculating the 2016 interim transmission tariff.

Alberta Electric System Operator Request for a Determination of the Cost Allocation of the Critical Infrastructure Protection Alberta Reliability Standards (Disposition Letter 3443)
Reliability Standards – Cost Allocation

The Alberta Electric System Operator ("AESO") requested that the AUC provide advice and directions pursuant to section 8 of the *Alberta Utilities Commission Act* ("*AUCA*") on the issue of cost responsibility for compliance with the Critical Infrastructure Protection ("CIP") reliability standards.

This request is related to the AUC's prior Decision 3441-D01-2015 and Decision 3442-D01-2015 regarding the CIP reliability standards. In those decisions, the AUC communicated to the AESO that it would determine cost responsibility for the CIP reliability standards under its rate-making authority under section 30 of the *Electric Utilities Act*, instead of section 8 of the *AUCA*. The AUC determined that it would institute a separate proceeding for that purpose as a separate module of the ISO tariff.

The AUC determined that there was still a large amount of relevant information to be ascertained, and that it would proceed to determine cost responsibility for CIP reliability standards as follows:

(a) The AUC directed the AESO to include in its next general tariff application whether it planned to include costs for CIP reliability standards in the ISO Tariff, including a rationale for its position;

(b) The AUC held that due to the nature of the information required from parties, any submissions will be given confidential treatment; and

(c) The AUC thereby closed Proceeding 3443 without making any determination of cost responsibility for CIP reliability standards.

EPCOR Distribution & Transmission Inc. 2016 Annual Performance-Based Regulation Rate Adjustment Filing (Decision 20821-D01-2015)
Performance-Based Regulation Rate Adjustment

EPCOR Distribution & Transmission Inc. ("EDTI") filed its 2016 annual performance-based regulation ("PBR") rate adjustment filing, and requested approval of its distribution access service ("DAS") rates and changes to its terms and conditions of service, effective January 1, 2016 on an interim basis.

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"). EDTI did not apply for a Z Factor adjustment.

EDTI's PBR rates were originally approved in Decision 2012-237, Decision 2013-462 and Decision 2014-346.

<u>2016 Updates to I Factor and I-X Mechanism</u>

As part of EDTI's submissions, it filed an update to its I Factor of 2.06 percent based on data vector v79311387 from Statistics Canada Table 281-0063 to calculate Alberta average weekly earnings figures, as the previous Statistics Canada tables had been terminated. Together with EDTI's X Factor of 1.16 percent approved in Decision 2012-237, EDTI requested approval of its I-X index value of 0.90 percent for 2016.

With the exception of the escalation of costs under the I-X mechanism, EDTI proposed no other changes to its terms and conditions of service.

No parties objected to EDTI's updated calculations, and the AUC approved EDTI's 2016 I Factor and resulting I-X mechanism for 2016 as filed, finding the calculations to be reasonable.

<u>Y Factor</u>

EDTI requested the following 2016 Y Factor amounts:

Y Factor	**2016 Amounts ($ million)**
AESO flow-through items	0.11
AUC assessment fees	1.48
Effects of regulatory decisions	-
Intervener costs	0.11
Commission tariff billing and load settlement initiatives	0.04
Property, business & linear taxes	7.51
Y Factor carrying charges	(0.01)
Total	**9.23**

EDTI submitted that it was unable to forecast on a reasonable basis, the costs associated with AUC tariff billing and load settlement initiatives or effects of regulatory decisions. Amounts applied for by EDTI in respect of these accounts were true-up costs for 2014 and 2015.

EDTI noted that it's requested 2016 Y Factor costs included, for the first time, capitalized incentive pay costs. However, it noted that the increased costs were less than $50, and were therefore immaterial.

After review, the AUC determined that EDTI's requested Y Factor amounts for 2016 were properly calculated and adequately supported. The AUC also agreed with EDTI's submission that the additional incentive pay costs were immaterial. Accordingly, the AUC approved EDTI's 2016 Y Factor amounts for these costs as filed, totalling $9.23 million.

K Factor Placeholder

EDTI requested a K Factor placeholder in the amount of $24.81 million for 2016, which is equal to 90 percent of its requested $27.57 million for EDTI's 2016-2017 forecast PBR capital tracker application.

No party objected to EDTI's application of a 90 percent placeholder for its 2016 K Factor.

The AUC approved EDTI's 90 percent proposed K Factor placeholder as filed, noting that the forecast placeholder provides a reasonable level of funding and reduces the potential for customer rate shock in future proceedings.

2016 Billing Determinants and Rate Riders

EDTI submitted that it made no changes to the methods used to calculate its forecast billing determinants, which were based on short-run forecasting (as previously approved in Decision 2014-346). There were no objections to EDTI's proposed 2016 billing determinants.

EDTI submitted that the variances between forecast and actual billings for 2013 and 2014, that were larger than 5 percent, were caused by higher than historical energy consumption, errors in forecast calculations for the traffic light rate class, and the implementation of light-emitting diode (or LED) lamps for the lane lights rate class.

The AUC approved EDTI's proposed 2016 billing determinants as filed. The AUC directed EDTI to provide information concerning any variances from forecast to actual by rate class, and to identify the causes of variances in billing determinants that exceed ± 5 percent in its next PBR filing.

EDTI proposed to continue collection of the following four distribution riders:

Distribution Rider	Description
Local Access Fee	A surcharge imposed by the City of Edmonton.
Rider DG	Applicable to true-up the results from Generic Cost of Capital Proceedings.
Rider DJ	Mechanism to true-up interim distribution rates to final distribution rates.
Rider E	Applicable to facilities constructed by the company on customer owned or leased property, as requested by the customer.

EDTI also proposed to continue collection of the following three transmission riders:

Transmission Rider	Description
Rider G	Mechanism to flow Balancing Pool rebates or charges to customers.
Rider J	Mechanism to true-up interim system access service rates to final system access services rates.
Rider K	Mechanism to deal with the estimated AESO transmission access charges deferral amounts on a quarterly basis.

While EDTI noted that it did not require a rider DG and DJ, it submitted that these riders could be addressed as a component of the annual PBR rate filing rather than through the use of riders. EDTI submitted that such an approach could reduce the regulatory burden and improve rate stability. However, since rate increases may be limited, EDTI stated that it would be helpful to continue its application as a rider to true-up material differences on a more timely basis.

No party objected to EDTI's continued use of its rate riders.

The AUC held that the transmission and distribution riders were necessary to address flow-through or AUC directed items such as Y Factors, and thereby approved the riders as applied for by EDTI.

Financial Reporting Requirements

As directed by the AUC in Decision 2012-237, EDTI submitted a copy of its Rule 005: *Annual Reporting Requirements of Financial and Operational Results* ("*Rule 005*") filing, which included, among other items, the equity thickness, return on equity figures and a confirmation that the assumptions and calculations in the application were accurate and complete.

The AUC determined that EDTI's *Rule 005* filing was compliant with its direction in Decision 2012-237. However, the AUC noted that the *Rule 005* filing disclosed two changes relating to the allocation of incentive pay and changes to meter depreciation. As the AUC found that these matters were being considered in Proceeding 20407, it declined to rule on those specific changes.

Rates and Bill Impacts

EDTI proposed to update customer specific ("CS") rates CS39, CS40, and proposed a new rate, CS41.

With respect to CS40, EDTI submitted that the CS40 rate class was previously approved in Decision 2014-346. EDTI submitted that the CS39 and CS40 rates were calculated on a weighted average cost of capital ("WACC") rate of 6.99, using the interim return on equity of 8.75 percent for 2014. EDTI proposed to update CS39 and CS40 calculations by applying a WACC rate of 6.50 percent pursuant to the AUC's directions in Decision 2191-D01-2015. EDTI submitted that this resulted in a refund of $3,090 to the CS39 rates, and a refund of $3,281 to the CS40 rates for 2014 and 2015.

With respect to CS41, EDTI sought approval for a new CS rate, as the customers' demand exceeded the 5,000 kilowatt-ampere (kVA) maximum for the time of use primary (or TOUP) class. EDTI submitted that the CS41 rate would be calculated using a method identical to all other CS rate classes.

The AUC held that the calculations for CS39, CS40 and CS41 were reasonable and consistent with previously approved methodologies. Accordingly the AUC approved the proposed changes to CS39 and CS40, and approved the new CS41 rate.

EDTI submitted that the bill impacts for its proposed 2016 rates would be as follows:

Rate Class Description	**Bill Change (%) from December 2015 to January 2016**
Residential	1.47
Small Commercial	0.11
Medium Commercial	8.05
Time of use – Secondary	5.30
Direct connects	0.31
Time of use – Primary	2.00
Street Lights	(0.54)
Traffic Lights	6.36
Lane lights	(5.32)
Security lights	0.63
Customer Specific	2.91
Customer Specific totalized	(3.03)
Small Commercial unmetered – Booth Lamp	1.27
Small Commercial unmetered – TV Booster	0.93
Small Commercial unmetered – China Gate	0.26

The AUC held that while it considers 10 percent to be a threshold that is indicative of rate shock, the AUC found that the bill impacts for all customer classes would be below 10 percent. The AUC determined that the bill impacts would therefore not cause rate shock to consumers.

The AUC noted that the 2016 rates reflect the inclusion of a 90 percent K Factor placeholder, and that rates are interim until approved on a final basis by the AUC.

As a result of the above findings, the AUC ordered that the distribution rates and special charges contained in

Appendix 4 and Appendix 5 of this decision be approved on an interim basis effective January 1, 2016.

Terms and Conditions

EDTI proposed mostly minor changes to its terms and conditions, but also included a revision distribution connection service which reflected the implementation of the Advanced Metering Infrastructure ("AMI" or smart metering) fees. EDTI proposed the ability for EDTI to install an AMI meter at a site where a customer has previously opted out once that customer discontinues service. EDTI also proposed to include a non-standard meter reading fee and non-standard meter installation fee for those consumers who do opt-out of the AMI program.

No party expressed concern with EDTI's proposed changes to its terms and conditions.

The AUC held that, given the AUC's prior approval of the AMI program in capital tracker proceedings, EDTI's proposed changes were reasonable and approved the changes as filed, effective January 1, 2016.

Accordingly, the AUC ordered that EDTI's 2016 distribution access service tariff, as well as its terms and conditions, be approved on an interim basis as set out in Appendix 6 to the decision, effective January 1, 2016.

AltaGas Utilities Inc. 2016 Annual Performance-Based Regulation Rate Adjustment Filing (Decision 20823-D01-2015)
Performance-Based Regulation Rate Adjustment

AltaGas Utilities Inc. ("AltaGas") filed its 2016 annual performance-based regulation ("PBR") rate adjustment filing, and requested approval of its distribution rates and special charges schedule effective January 1, 2016 on an interim basis.

(See the EPCOR Distribution & Transmission Inc. case in this report regarding the PBR framework, as described by the AUC.)

AltaGas' PBR rates were originally approved in Decision 2012-237, Decision 2013-465 and Decision 2014-357.

2016 Updates to I Factor and I-X Mechanism

As part of AltaGas' submissions, it filed an update to its I Factor of 2.06 percent based on data vector v79311387 from Statistics Canada Table 281-0063 to calculate Alberta average weekly earnings figures, as the previous Statistics Canada tables had been terminated. Together with AltaGas' X Factor of 1.16 percent approved in Decision 2012-237, AltaGas requested approval of its I-X index value of 0.90 percent for 2016.

With the exception of the escalation of costs under the I-X mechanism, AltaGas proposed no other changes to its terms and conditions of service.

No parties objected to AltaGas' updated calculations, and the AUC approved AltaGas' 2016 I Factor and resulting I-X mechanism for 2016 as filed, finding the calculations to be reasonable.

Y Factor

AltaGas requested the following 2016 Y Factor amounts:

Y Factor	**2016 Forecast ($)**
AUC assessment fees	308,407
Office of the Utilities Consumer Advocate ("UCA") Assessment fees	89,326
Intervener hearing costs	188,140
Income tax temporary differences	(1,239,430)
Natural gas settlement system code ("NGSSC") related costs	1,289,089
Customer information system	177,063
2013 and 2014 Y Factor True-up	8,221
Total	**820,817**

AltaGas submitted that it's forecasted AUC assessment fees were indexed using the I-X mechanism for 2016. The UCA assessment fees were, in AltaGas' submission, based on the most recent Ministerial Order covering the fiscal period from April 1, 2013 to March 31, 2014, and adjusted by the I-X mechanism for 2016. AltaGas submitted that it expected to make further adjustments to the UCA assessment fees once it receives the Ministerial Order for the fiscal period April 1, 2014 to March 31, 2015.

With respect to intervener hearing costs, AltaGas submitted that its forecast amount for 2016 was based on "a combination of professional judgment and AUC cost awards for similar proceedings."

With respect to income tax temporary differences, AltaGas submitted that the credit for 2016 is largely due to differences between tax and book depreciation, as well as items capitalized for book purposes.

AltaGas forecasted its NGSSC revenue requirements in three parts:

(a) Phase 1 capital-related costs of $377,028;

(b) Phase 2 capital-related costs of $568,361; and

(c) Operating costs of $343,700.

AltaGas also noted that its 2016 forecast operating costs are lower than 2015 costs as a result of lower contracted application support services as a result of transitioning to internal AltaGas resources for routine technical maintenance and operational support.

AltaGas explained that the customer information system costs were a Y Factor cost as such costs are outside AltaGas' management's control, since such costs are driven by the AUC's direction pursuant to *Rule 004* and *Rule 028*, and would exceed the materiality threshold of $325,000 established in Decision 2012-237.

After review, the AUC determined that AltaGas' requested Y Factor amounts for 2016 for AUC assessment fees, UCA assessment fees, intervener hearing costs and income tax temporary differences were reasonable and consistent with methodologies used in previous PBR annual filings. Accordingly, the AUC approved AltaGas' 2016 Y Factor amounts for these costs as filed, totalling $643,754.

With respect to customer information system costs, the AUC noted AltaGas applied for an exemption from compliance with the NGSSC requirements of *Rule 004* and *Rule 028*. The AUC also noted that while the applied-for exemptions were granted in Decision 3606-D01-2015 and Decision 20428-D01-2015, the AUC did not make a specific direction for AltaGas to correct the noncompliances, but rather to provide updates on its progress to become compliant.

Accordingly, the AUC determined that the customer information system costs requested by AltaGas for 2016 were not events outside of management's control, and that there was insufficient evidence on the record to determine the prudence of such costs. Therefore the AUC denied $177,063 of 2016 NGSSC customer information system costs from AltaGas' requested Y Factor.

K Factor Placeholder

AltaGas requested a K Factor placeholder in the amount of $4.86 million for 2016. The K Factor, in AltaGas' submission was composed of two components:

(a) A 90 percent placeholder of $5.27 million for AltaGas' 2016-2017 forecast PBR capital tracker application of $5.85 million; and

(b) A 2014 K Factor true-up refund of $393,854, and a 2013 K Factor refund of $11,217.

AltaGas noted that the 2013 figures account for pipeline replacement costs that were denied in Decision 2014-373, and reapplied for later. AltaGas also noted that its 2014 K Factor adjustments were the result of actual capital additions being six percent lower than forecast.

There were no objections to AltaGas' 2016 K Factor placeholder.

The AUC approved the 90 percent proposed K Factor placeholder as filed, noting that the forecast placeholder provides a reasonable level of funding and reduces the potential for customer rate shock in future proceedings.

Financial Reporting Requirements

As directed by the AUC in Decision 2012-237, AltaGas submitted a copy of its Rule 005: *Annual Reporting Requirements of Financial and Operational Results* ("*Rule 005*") filing, which included among other items the equity thickness, return on equity figures and a confirmation that the assumptions and calculations in the application were accurate and complete.

The Consumers' Coalition of Alberta ("CCA") raised concerns whether AltaGas had applied the correct equity thickness for its return on equity percentages in 2013 and 2014, submitting that AltaGas used blended equity thickness ratios of 42.83 and 42.77 percent respectively. The CCA noted that the blended ratios arose from AltaGas applying 43 percent equity to PBR rate base excluding Y and K Factors, and 42 percent PBR rate base to Y and K Factors. The CCA submitted that the correct equity thickness for 2013 and 2014 was 42 percent, based on the AUC's direction in Decision 2191-D01-2015, which dealt with generic cost of capital matters.

The AUC determined that AltaGas' *Rule 005* filing was compliant with its direction in Decision 2012-237. However, with respect to the CCA's concerns regarding equity thickness, the AUC noted that similar issues have arisen in the 2016 PBR rate adjustment filings for other companies, and that the AUC will be releasing a separate communication clarifying reporting requirements.

Accordingly, the AUC declined to rule on this specific issue in the decision.

2016 Billing Determinants and Rate Riders

AltaGas submitted that it made no changes to the methods used to calculate its forecast billing determinants. There were no objections to AltaGas' proposed 2016 billing determinants.

The AUC approved AltaGas' proposed 2016 billing determinants as filed. The AUC directed AltaGas to provide information concerning any variances from forecast to actual by rate class, and directed AltaGas to identify the causes of variances in billing determinants that exceed ± 5 percent in its next PBR filing.

With respect to rate riders, AltaGas proposed no changes to its existing nine rate riders for:

(a) Franchise fees;

(b) Property tax;

(c) Deemed cost of gas;

(d) Gas cost recovery;

(e) Unaccounted-for gas;

(f) Deficiency or refund from interim rates;

(g) Third-party transportation costs;

(h) Default gas supply providers' unaccounted-for gas; and

(i) Load balancing.

There were no objections to AltaGas' continued use of rate riders.

The AUC approved each of the nine rate riders, finding that each rider was necessary to address flow-through or Commission-directed items. The AUC noted that it will reassess the continuing need for rate riders at the time of AltaGas' next PBR rate adjustment filing.

Rates and Bill Impacts

AltaGas submitted that the bill impacts for the proposed 2016 distribution rates would be as follows:

Rate Class Description	**Bill Change (%) from December 2015 to January 2016**
Residential Rate 1/11	6.98
Commercial Rate 1/11	18.99
Rural Rate 1/11	8.67
Total Rate 1/11	10.67
Large General Service Rate 2/12	21.92
Demand Rate 3/13	5.43
Irrigation Rate 4/14	(5.52)

AltaGas noted that the overall rate impacts for 1/11 and 2/12 rate classes was more than 10 percent, while the overall rate impacts for 3/13 and 4/14 rate classes were below 10 percent. AltaGas explained that approximately half of the increase for 1/11 and 2/12 rate classes were attributable to increased forecast delivery revenues for December 2015 and January 2016.

The AUC held that while it considers 10 percent to be a threshold that is indicative of rate shock, it accepted AltaGas' explanation, and noted that when the bills for 1/11 and 2/12 rate classes are normalized for usage and commodity costs, the bill impacts are below 10 percent. The AUC determined that the bill impacts would therefore not cause rate shock to consumers.

The AUC noted that the 2016 rates reflect the inclusion of a 90 percent K Factor placeholder, and that rates are interim until approved on a final basis by the AUC.

As a result of the above findings, the AUC ordered that the distribution rates and special charges contained in Appendix 4 and Appendix 5 of this decision be approved on an interim basis effective January 1, 2016.

ATCO Electric Ltd. 2016 Annual Performance-Based Regulation Rate Adjustment Filing (Decision 20822-D01-2015)

Performance-Based Regulation Rate Adjustment

ATCO Electric Ltd. ("ATCO") applied to the AUC for approval of its 2016 annual performance-based regulation ("PBR") rate adjustment filing, requesting approval of its electric distribution services rates, transmission system access services ("SAS") tariff billing determinants and amended terms and conditions, to be effective January 1, 2016 on an interim basis.

(See the EPCOR Distribution & Transmission Inc. case in this report regarding the PBR framework, as described by the AUC.)

ATCO's PBR rates were originally approved in Decision 2012-237, Decision 2013-461 and Decision 2014-354.

2016 Updates to I Factor and I-X Mechanism

As part of ATCO's submissions, it filed an update to its I Factor of 2.06 percent based on data vector v79311387 from Statistics Canada Table 281-0063 to calculate Alberta average weekly earnings figures, as the previous Statistics Canada tables had been terminated. Together with ATCO's X Factor of 1.16 percent approved in Decision 2012-237, ATCO requested approval of its I-X index value of 0.90 percent for 2016.

No parties objected to ATCO's updated calculations, and the AUC approved ATCO's 2016 I Factor and resulting I-X mechanism for 2016 as filed, finding the calculations to be reasonable.

2016 Rate Base Adjustments

ATCO requested two adjustments to its 2012 forecast revenues used in its 2012 going-in rates, and its base rates for 2013, 2014 and 2015. ATCO submitted that each adjustment for 2012 through 2014 was as a result of the AUC directions in Decision 20026-D01-2015 related to the impact of the 2011 Slave Lake fires on rate base and the consequences flowing from AUC directions in Decision 2011-485. ATCO submitted that its 2015 adjustment reflects ATCO's purchase of the Delburne West rural electrification association ("REA"), calculated as of 2015.

ATCO submitted that the total value of all four adjustments escalated by the I-X mechanism for each year resulted in a net increase to rate base of approximately $1.7 million.

The AUC approved ATCO's proposed increases related to the 2011 Slave Lake fires as filed, finding them to be consistent with the directions given in Decision 20026-D01-2015.

With respect to the AUC's direction in Decision 2011-485, the AUC held that it would approve the proposed reductions on an interim basis, as it noted that the scope of ATCO's proposed reductions were at the time under consideration as part of Proceeding 3378. Therefore, the AUC directed ATCO to address any variance through a subsequent rate adjustment in a future PBR rate adjustment filing to give effect to any decision reached in Proceeding 3378.

The AUC approved ATCO's proposed increase in rate base arising from the purchase of the Delburne West REA as filed, finding that the adjustment proposed was equal to the purchase amount approved in Decision 2014-354.

Y Factor

ATCO requested the following 2016 Y Factor amounts:

Y Factor	2016 Forecast ($000)
Intervener hearing costs	1,596
AESO Load Settlement	(278)
Income tax deductible capital cost deferral account	(2,806)
Deduction of deferrals for income taxes	4,152
Slave Lake fires adjustments	(17,480)
Evergreen proceeding true-up	(7,189)
Warwick REA 2014-2016 revenue requirement	890
Stry REA 2015-2016 revenue requirement	1,453
Total	**(19,662)**

ATCO also requested the inclusion of a refund of $0.129 million for carrying charges for the above charges and credits, to be refunded over the period of January 1, 2016 to December 31, 2016.

ATCO submitted that its 2016 forecast for intervener costs was based on 2014 actual costs inflated by the I-X mechanism. The AESO load settlement forecast was based on load settlement charges for 2015. The income tax deductible capital cost deferral account and the deduction of deferrals for income taxes were calculated using an average of 2013 and 2014 capital repair costs.

The AUC approved each of the Y Factors for intervener hearing costs, AESO load settlement costs, income tax deductible capital cost deferral account costs and the deduction of deferrals for income taxes amounts as filed, holding that the accounts were previously approved as Y Factors, and that the methodologies were reasonable and consistent with previous PBR filings.

With respect to the 2011 Slave Lake fire adjustments, the AUC noted that it approved a $6.6 million Y Factor placeholder in respect of the $23.191 million that was charged to ATCO's reserve for injuries and damages account, and was directed to address any true-ups required in this 2015 PBR rate adjustment filing. However, in Decision 2014-297, the AUC determined that the costs would be treated as a capital addition instead of through the reserve for injuries and damages account. Therefore, the AUC ordered these Y Factor collections refunded, and included these in rate base instead in Decision 20026-D01-2015. The AUC held that ATCO's calculations for the Y Factor adjustments, including carrying costs and set offs for rate base adjustments, were reasonable and therefore approved them as filed.

The AUC determined that ATCO had complied with the direction in Decision 2014-169 related to the Evergreen 2014 going-in true up, and that the costs were reasonably calculated. However, because the scope of such costs was still being considered under Proceeding 3378, the AUC approved these costs on an interim basis.

With respect to the costs of the Warwick and Stry REAs, the AUC held that while each account qualified for Y Factor treatment as the acquisitions were the subject of an AUC order, the AUC determined that ATCO had applied incorrect equity ratios of 39 percent equity, 10 percent preferred equity, and a return on equity of 8.75 percent for each of Warwick and Stry REA. Accordingly, the AUC reduced the Warwick and Stry REA Y Factor amounts by \$0.102 million and \$0.167 million respectively. The AUC therefore approved recalculated Y Factor amounts for Warwick and Stry REA of \$0.788 million and \$1.286 million respectively.

K Factor Placeholder

ATCO requested a K Factor placeholder in the amount of \$48.2 million for 2016, equal to 100 percent of the 2016 K Factor forecast in ATCO's 2016-2017 PBR capital tracker application. ATCO submitted that a 100 percent placeholder was appropriate since the criteria for capital tracker treatment are well established, and virtually all of ATCO's capital tracker amounts were approved in its prior PBR capital tracker application.

The Office of the Utilities Consumer Advocate ("UCA") submitted that ATCO had not demonstrated the quantum or need for 100 percent of interim rates, citing Decision 2005-102, and argued that a placeholder of 90 percent would promote rate stability and ease rate shock, while still providing funding to ATCO. The Consumers' Coalition of Alberta ("CCA") supported the UCA's proposal.

The AUC agreed with the submission of the UCA and CCA, holding that a 90 percent placeholder for K Factor amounts would provide ATCO with adequate funding, and maintain rate stability. The AUC also held that a 90 percent placeholder was reasonable, as certain issues related to ATCO's 2014-2015 capital tracker application were still being considered under Proceeding 20555.

2016 Billing Determinants

ATCO submitted that it uses regional service installations projections to forecast its billing determinants, using a forecast customer count and a regression model with historical data. ATCO submitted that this methodology was approved in its previous PBR rate adjustment filing in Decision 2014-354.

ATCO explained that the variances from its prior forecasts were caused by existing customers reducing their demand, change in climate, customer cancellations, and changes to in-service dates, the purchases of REAs, and the resulting transfer of customers.

The CCA expressed concerns that ATCO was not flowing through the pro rata share of revenue differences of K, Y and Z Factors across rate classes, and recommended that the 2016 rates be adjusted accordingly.

The AUC held that ATCO's 2016 billing determinants forecast was reasonable and consistent with its previously approved PBR applications. The AUC found that the variances from forecasts could not have been reasonably expected by ATCO, and did not undermine the validity of ATCO's forecasting model.

Rate Riders

With respect to rate riders, ATCO proposed no changes to its existing six rate riders for:

(a) Municipal adjustments;
(b) Balancing Pool adjustment;
(c) Special facilities charges;
(d) Temporary adjustments;
(e) Interim adjustments; and
(f) SAS quarterly charges.

There were no objections to ATCO's continued use of rate riders.

In response to a filing by the Alberta Electric System Operator ("AESO") that sought an amendment to the AESO's Balancing Pool Consumer Allocation Rider, ATCO proposed to revise its requested Rider B to correspond with the AESO's requested Balancing Pool Consumer Allocation Rider for 2016.

ATCO submitted that while its interim adjustments account has a balance of zero, it proposed to maintain it for future charges or refunds approved by the AUC in the future.

The AUC approved each of the six rate riders, finding that each rider was necessary to address flow-through or AUC-directed items. The AUC noted that it will reassess the continuing need for rate riders at the time of ATCO's next PBR rate adjustment filing.

Financial Reporting Requirements

As directed by the AUC in Decision 2012-237, ATCO submitted a copy of its Rule 005: *Annual Reporting Requirements of Financial and Operational Results* ("*Rule 005*") filing, which included, among other items, the equity thickness, return on equity figures and a confirmation that the assumptions and calculations in the application were accurate and complete.

The AUC determined that ATCO's *Rule 005* filing was compliant with its direction in Decision 2012-237, and approved this portion of the application as filed.

2016 Rates

ATCO requested approval of its SAS rates for 2016, to be effective on January 1, 2016. ATCO submitted that its SAS rates were reflective of the rate proposed by the AESO in its 2015 tariff for demand transmission service. ATCO applied a scaling approach to its 2015 rates approved in Decision 2014-354 in order to calculate the 2016 SAS rates. ATCO noted that this methodology has been consistently applied since its 2005-2006 general tariff application.

There were no objections to ATCO's calculation of the 2016 SAS rates.

ATCO submitted that the bill impacts for the proposed 2016 distribution rates would be as follows:

Rate Class Description	Bill Change (%) from December 2015 to January 2016
D11 Residential	2.2
D21	3.2
D25	(3.6)
D31	0.8
D41	2.4
D51	1.8
D56	3.0
D61	0.9
D61	0.8
D63	1.1
T31	0.0

The AUC noted that it considers 10 percent to be a threshold that is indicative of rate shock, and found that the bill impacts as calculated by ATCO would be less than 10 percent for all rate classes. While the AUC noted that these impacts did not account for the change to the Balancing Pool rider which ATCO had changed in response to the AESO's filing, it held that the magnitude of the change would not affect its finding in this regard. The AUC therefore found that ATCO's 2016 PBR rate calculations were reasonable, and approved ATCO's 2016 PBR rates on an interim basis, effective January 1, 2016.

The AUC approved ATCO's proposed 2016 SAS rates on an interim basis, holding that the calculations were reasonable and were consistent with past SAS rate applications.

Amendments to Price Schedules, and Terms and Conditions

ATCO proposed a number of changes to its price schedule, including the following:

(a) The addition of a footnote to all price schedules;

(b) The removal of price schedule D22 (Small General Service - Energy Only);

(c) Wording changes to price schedules D31 (Large General Service/Industrial - Distribution Connected) and D32 (Generator Interconnection and Standby Power - Distribution Connected) to clarify the transmission ratchet calculation;

(d) A wording change to Rider A (Municipal Assessment) to accommodate the franchised communities proposal to charge farm customers a franchise tax, and to be consistent with Rider B (Balancing Pool Adjustment); and

(e) A wording addition to the Rider S (System Access Service Adjustment) availability description to clarify that customers on an isolated industrial areas rate are exempt.

There were no objections to ATCO's proposed changes to its price schedules.

The AUC considered the changes to be largely of an administrative nature, with the exception of removing price schedule D22. The AUC noted that, while rate D22 did not currently have any customers, the elimination of this rate may impact ATCO's customers. Therefore, the AUC declined to issue a determination on removing price schedule D22 at the time of the decision.

The AUC otherwise approved all of ATCO's proposed changes as filed.

ATCO also proposed a number of substantive and administrative changes to its terms and conditions. However, the AUC determined that, aside from the administrative changes, substantive changes were outside the approved scope of the proceeding, and the AUC therefore declined to rule on the proposed substantive changes in this decision.

Accordingly, the AUC ordered as follows:

(a) ATCO's 2016 distribution rates as set out in Appendix 4 of the decision were approved on an interim basis, effective January 1, 2016;

(b) ATCO's 2016 Balancing Pool Rider B was approved, effective January 1, 2016; and

(c) ATCO's terms and conditions of service for customers and retailers as set out in Appendices 5 and 6 respectively, were approved, effective January 1, 2016.

FortisAlberta Inc. 2016 Annual Performance-Based Regulation Rate Adjustment Filing (Decision 20818-D01-2015)
Performance-Based Regulation Rate Adjustment

FortisAlberta Inc. ("Fortis") applied to the AUC for approval of its 2016 annual performance-based regulation ("PBR") rate adjustment filing, requesting approval of its 2016 rates, to be effective January 1, 2016, on an interim basis.

(See the EPCOR Distribution & Transmission Inc. case in this report regarding the PBR framework, as described by the AUC.)

Fortis' PBR rates were originally approved in Decision 2012-237, Decision 2013-464 and Decision 2014-351.

2016 Updates to I Factor and I-X Mechanism

As part of Fortis' submissions, it filed an update to its I Factor of 2.06 percent based on data vector v79311387 from Statistics Canada Table 281-0063 to calculate Alberta average weekly earnings figures, as the previous Statistics Canada tables had been terminated. Together with Fortis' X Factor of 1.16 percent approved in Decision 2012-237, Fortis requested approval of its I-X index value of 0.90 percent for 2016.

No parties objected to Fortis' updated calculations, and the AUC approved Fortis' 2016 I Factor and resulting I-X mechanism for 2016 as filed, finding the calculations to be reasonable.

Y Factor Adjustments

Fortis applied for the following Y Factor adjustments as part of its 2016 PBR application:

Y Factor	**Total ($000)**
AUC Assessment Fees	2.0
Hearing Costs for Interveners	0.1
AESO Load Settlement Costs	0.3
Property and Business Taxes	1.6
Farm Transmission Credit	(4.8)
Kingman REA	0.3
VNM REA	0.8
Carrying Charges	0.0
Total	**0.3**

Fortis submitted that it forecasted the AUC assessment fees, and hearing cost reserves for interveners based on prior year approved forecasts. Fortis submitted that it applied the I-X mechanism to update prior year forecasts for AESO load settlement costs and farm transmission credit costs. With respect to property tax costs, its forecasts were based on average percentage changes for the last three years, multiplied by the actual total paid in the prior year. For business taxes, it adjusted prior year actual values for inflation.

For the purchases of the Kingman and VNM Rural Electrification Associations ("REA"), Fortis proposed to collect the revenue requirement for each REA as a Y Factor for 2016. However, Fortis proposed to incorporate the REAs into base rates, in a manner similar to ATCO Electric Ltd., as approved in Decision 2014-044.

The Office of the Utilities Consumer Advocate ("UCA"), among others, submitted that Fortis' purchase of the Kingman and VNM REAs were not the result of a direction from the AUC to include them as a Y Factor, and by that fact, did not satisfy the requirement that a Y Factor charge be the subject of an AUC direction.

The AUC held that in order for the Kingman and VNM REA acquisitions to qualify for Y Factor treatment, Fortis bore the burden of demonstrating that the AUC directed Fortis to acquire the REAs in question. The AUC held that Fortis had done so, by successfully applying to the AUC for the acquisition of each REA. The AUC therefore dismissed the UCA's argument. The fact that Fortis did not seek specific direction to include the REA acquisition cost as Y Factor at the time of acquisition.

The AUC found that Fortis' calculations for its 2016 Y Factor charges were adequately supported and properly calculated. The AUC accordingly approved Fortis' 2016 Y Factor charges as filed. The AUC also approved the inclusion of the Kingman and VNM REAs into rate base for 2017, to be escalated by the I-X mechanism.

<u>K Factor Adjustments</u>

Fortis proposed to collect a K Factor placeholder for 2016 in the amount of $71.5 million, equal to 100 percent of its forecast 2016 K Factor amounts in its 2016-2017 PBR capital tracker application on an interim basis. However, in response to an information request from the AUC, Fortis indicated that it would be supportive of a 2016 K Factor placeholder at 90 percent of its forecast 2016 K Factor amounts in its 2016-2017 PBR capital tracker application.

The AUC determined that a 2016 K Factor placeholder at 90 percent of Fortis' forecast 2016 K Factor amounts in its 2016-2017 PBR capital tracker application, on an interim basis, would provide a reasonable level of funding to Fortis on a timely basis and would reduce the potential for rate shock.

Therefore, the AUC approved Fortis' K Factor placeholder for 2016 in the amount of $64.372 million on an interim basis.

<u>Rate Riders</u>

Fortis proposed to continue collection of the following four distribution riders:

(a) Rider A-1 municipal assessment rider;

(b) Municipal franchise fee riders;

(c) Distribution adjustment rider; and

(d) Rider E, customer specific facilities.

Fortis also proposed to continue collection of the following three transmission riders:

(a) Balancing Pool allocation rider;

(b) Base transmission adjustment rider; and

(c) Quarterly transmission adjustment rider.

While Fortis noted that it did not require a distribution adjustment rider for 2016, Fortis submitted that it could be required in the future to accommodate true-ups not associated with K, Y, and Z Factors.

No party objected to Fortis' continued use of its rate riders.

The AUC held that the transmission and distribution riders were necessary to address flow-through or AUC directed items such as Y Factors, and thereby approved the riders as applied for by Fortis.

<u>Financial Reporting Requirements</u>

As directed by the AUC in Decision 2012-237, Fortis submitted a copy of its Rule 005: *Annual Reporting Requirements of Financial and Operational Results* ("*Rule 005*") filing, which included among other items the equity thickness, return on equity figures and a confirmation that the assumptions and calculations in the application were accurate and complete.

The AUC determined that Fortis' *Rule 005* filing was compliant with its direction in Decision 2012-237, and approved this portion of the application as filed.

<u>2016 PBR Rates and Bill Impacts</u>

Fortis provided bill impacts reflecting its proposed rates in response to an AUC information request, as follows:

Rate Class Description	Bill Change (%) December 2015 vs. January 2016
Rate 11 – Residential	0.5
Rate 21 – FortisAlberta Farm	2.2

Rate 24 – REA Farm	N/A
Rate 26 – FortisAlberta Irrigation	10.0
Rate 29 – REA Irrigation	N/A
Rate 3X – Exterior Lighting	(6.6)
	(1.8)
	(4.7)
Rate 41 – Small General Service	7.8
Rate 44/45 – Oil & Gas Service	8.7
Rate 61 – General Service	6.4
Rate 63 – Large General Service	8.3

The UCA argued that the AUC, for 2015, approved rates that resulted in a bill increase of 30 percent for irrigation customers in Decision 2014-351. The UCA argued that a bill increase of 30 percent followed by a bill increase of, what it calculated as approximately, 19 percent was unacceptable.

In response, Fortis provided a mitigation strategy which would limit the impact to a 10 percent increase for the December 2015 to January 2016 time period by allocating a disproportionate amount of the 2016 K Factor placeholder reduction for irrigation customers.

The UCA stated that such mitigation would result in cross-subsidization. The UCA was, however, supportive of strategies that would limit bill impacts to 10 percent.

The AUC held that it normally considers an increase of 10 percent or more to constitute rate shock, and that the 2016 PBR rates proposed by Fortis would result in a bill impact of 19.5 percent for the irrigation rate class. Therefore the AUC found that such an increase would constitute rate shock, and that a mitigation strategy was required. The AUC held that Fortis' proposed mitigation strategy through the allocation of the K Factor placeholder was appropriate, since the K Factor was an interim placeholder, and therefore would not constitute cross-subsidization at this time. Accordingly, the AUC approved Fortis' proposal to limit rate impacts, to irrigation classes, to 10 percent by re-allocating the 2016 K Factor.

Revenue to Cost Ratios

The CCA raised concerns about overcharging residential customers since Fortis had not adjusted its revenue to cost ratios to achieve a value in the 95 to 105 percent range.

Fortis argued that the next opportunity to revise revenue to cost ratios was in its next Phase II tariff application, which it noted typically occurs once every four years. Fortis also noted that its last Phase II tariff was implemented on January 1, 2015. Fortis suggested that it may be more feasible to consider the synchronization of its next Phase II tariff application with the beginning of its next PBR term.

The AUC held that changes to the revenue to cost ratios were outside the scope of the current application, and should be considered as part of the next Phase II tariff application. However, the AUC noted that the CCA will have the opportunity to raise this issue as part of the next generation of PBR plans in Proceeding 20414.

Terms and Conditions

Fortis applied for amendments to its terms and conditions of service to incorporate changes to fee tables, escalation factors and other administrative items. There were no objections to Fortis' proposed changes.

The AUC held that the changes to the terms and conditions to reflect the change in service fees were consistent with the AUC's directions in Decision 2013-270, and approved the changes as filed, effective January 1, 2016.

Accordingly, the AUC ordered that the Fortis' 2016 rates, options and riders, set out in Appendix 5 of the decision be approved effective January 1, 2016 on an interim basis. The AUC also approved Fortis' customer and retailer terms and conditions of service effective January 1, 2016.

Genalta Power Inc. Preferential Sharing of Records between Genalta II Limited Partnership, a wholly owned affiliate of Genalta Power Inc., and URICA Energy Real Time Ltd. (Decision 21104-D01-2015)
Preferential Sharing of Records

Genalta Power Inc. ("Genalta Power") applied for an order under section 3 of the *Fair, Efficient and Open Competition Regulation* (the "*FEOC Regulation*") permitting the sharing of records not available to the public between Genalta II Limited Partnership ("Genalta") and URICA Energy Real Time Ltd. ("URICA").

Genalta and URICA had previously been permitted to share records in relation to the output of two 15 megawatt natural gas-fired generating units pursuant to Decision 2014-030. That decision permitted the sharing of records from February 7, 2014 until December 31, 2015 or the termination of the agreement between Genalta and URICA.

Genalta Power's application sought a continuation of the records sharing between Genalta and URICA.

The Market Surveillance Administrator filed a statement of intent to participate, advising that it supported the application.

The AUC, in providing its findings on the application, stated that Section 5(5) of the *FEOC Regulation* prohibits a market participant from holding offer control in excess of 30 percent of the total capability of generating units in Alberta.

Genalta Power submitted that it would have well below the 30 percent limit, with 0.12 percent offer control of the energy market if the AUC approves the application, while URICA and its associates represented 0.31 percent offer control of the energy market and 14.5 percent of the operating reserves market.

The AUC held that the offer control held by Genalta Power would not exceed the 30 percent maximum. The AUC determined that no confidential information would be shared between Genalta Power and URICA for the purposes of price-fixing, price-manipulation or any other prohibited conduct under the *FEOC Regulation*.

Accordingly, the AUC issued an order permitting the sharing of records between Genalta Power and URICA for each of the 15 megawatt natural gas-fired generating units, effective December 18, 2015 to December 31, 2020, or until the termination of the agreement between Genalta and URICA, whichever expires sooner.

ATCO Electric Ltd. Application for the Disposition of the Steepbank River 836S Substation (Decision 21042-D01-2015)

Disposition of Substation

ATCO Electric Ltd. ("ATCO") applied to the AUC pursuant to section 101(2)(d) of the *Public Utilities Act* to dispose of its Steepbank River 826S substation ("Substation"). The Substation is located within Suncor Energy Inc.'s ("Suncor") industrial system.

ATCO proposed to sell the Substation to Suncor, and remove it from rate base. ATCO submitted that the approximate net book value of the Substation was $2.3 million, composed of the following assets:

(a) A developed site including ground grid, gravel, fence, bus work, full basement control building and associated equipment;

(b) Five 72/13.8-kilovolt (kV) transformers with associated protection and control;

(c) Ten 72-kV breakers and several switches with associated protection and control; and

(d) Associated electrical components including station service, metering, current transformers, potential transformers, telecommunication and SCADA (supervisory control and date acquisition).

ATCO noted that the Substation was built, operated and maintained for Suncor's sole use. It also entered into an agreement on October 16, 1989 with Suncor for ATCO to recover the capital and maintenance costs of the Substation from Suncor by way of negotiated revenue offset with a term of 18 years effective November 1, 1987. This revenue offset was included in ATCO's revenue requirement through Rider E – Special Facilities Charge Revenue. ATCO and Suncor both submitted to the AUC that they had negotiated a commercial agreement whereby Suncor would assume ownership of the Substation.

ATCO submitted that the disposition would be outside the ordinary course of business for ATCO, and thereby necessitated consent from the AUC prior to a sale. ATCO submitted that the anticipated proceeds of sale would exceed the $1.5 million threshold established for other utilities, such as ATCO Gas in Decision 2013-417. ATCO also submitted that the transaction was a rare occurrence in its operating history.

In holding that the disposition was outside the ordinary course of ATCO's business, the AUC applied its test developed in Order U2001-196. In Order U2001-196, the AUC established that a utility must satisfy the AUC that the transaction will have a material impact on rate base, and that the type of transaction is infrequent.

With respect to materiality, the AUC determined that the net book value of the Substation was within the range of previous approvals, and was therefore reasonable. However, the AUC directed ATCO to provide evidence related to the anticipated proceeds of disposition in future applications to assist the AUC in making a finding on materiality.

With respect to frequency and type of transaction, the AUC accepted ATCO's submission that the disposition of a substation was a rare occurrence.

ATCO submitted that the disposition would not have any negative effects on ratepayers, consistent with the "no harm" test applied by the AUC on previous occasions. ATCO submitted that the transfer would also not affect safety, quality or reliability of services, given that the Substation was constructed and maintained solely for Suncor's use. ATCO also submitted that there would be no financial harm to ratepayers, as the costs of the Substation were at all times subject to a full revenue offset under Rider E, and that Suncor would be responsible for all future claims, losses and environmental issues of the Substation under the terms of their agreement.

The AUC held that it was satisfied with ATCO's representations that the transfer would not cause any harm to ratepayers, and would not have any impact on the quality of service provided.

ATCO submitted that, if the transaction was to be approved, it would remove the Substation from rate base and discontinue the collection of revenues under Rider E, effective on the date of the transfer to Suncor, at the time scheduled for January 15, 2016.

Based on its finding that ratepayers would not be harmed, and ATCO's representation that the costs of the disposition would be on the account of Suncor, the AUC approved the proposed removal of the Substation from rate base, effective on closing.

The AUC further directed ATCO to advise of the closing date in a post-disposition filing, and identify all rate base adjustments as well as adjustments to operating and maintenance costs as a result of the transfer.

Therefore, the AUC approved ATCO's application to dispose of the Substation.

Response to Blazer Water Systems Ltd. Letter to the AUC (Disposition 20930-D01-2015)
Response to Complaint Letter

The AUC released a letter decision relating to a complaint from a customer of Blazer Water Systems Ltd. ("Blazer") in respect of new charges for water rates.

In response, the AUC directed Blazer to discontinue charging its new water rates, as the AUC held that a utility may not increase its rates without leave of the AUC pursuant to section 103 of the *Public Utilities Act*. The AUC also noted that it has not, to date, ruled on or received an application from Blazer to change its water rates.

Blazer, by letter dated December 2, 2015, agreed with the AUC that it was not legally able to increase its water rates without leave of the AUC. Blazer also advised the AUC that it will stop charging its revised water rates, and revert to the previously approved amount, with the amounts collected under the revised rate being held in a deferral account. Blazer advised that it would file a general rate application in 2016.

The AUC therefore closed the complaint proceeding, given that Blazer discontinued the application of its new water rates. The AUC held that it would consider how to treat the amounts in the deferral account in Blazer's upcoming general rate application.

AltaLink Management Ltd. 2016 Interim Transmission Facility Owner Tariff (Decision 21168-D01-2015)
Interim Tariff

AltaLink Management Ltd. ("AltaLink") applied for approval of its 2016 interim transmission facility owner ("TFO") tariff. AltaLink requested to continue recovering its 2015 interim TFO tariff as approved in Decision 3504-D01-2015, effective January 1, 2015 and until such time as the AUC renders a final decision in respect of AltaLink's 2015-2016 general tariff application ("GTA").

The Consumers' Coalition of Alberta stated that it had no objection to the application.

AltaLink submitted that its current 2015 interim tariff was approved on an interim refundable rate of $60,787,500 per month, effective January 1, 2015, reflecting 90 percent of AltaLink's forecast revenue requirement for 2015.

The AUC noted that the proceeding to consider AltaLink's GTA was underway at the time of the decision, and that the oral portion of the hearing had already concluded. The AUC also determined that AltaLink's 2015 interim tariff would expire prior to the AUC issuing a final decision in the proceeding. Therefore the AUC held that continuing the interim rate for a short duration into 2016 would not result in any harm to ratepayers and would provide adequate funding to AltaLink.

Accordingly, the AUC approved AltaLink's request to continue its 2015 interim TFO tariff of $60,787,500 per month, effective January 1, 2016 on an interim basis until a final decision is made in respect of AltaLink's current GTA.

NATIONAL ENERGY BOARD

Alliance Pipeline Ltd. Compliance Filing on Interruptible and Seasonal Bid Mechanics; Tenaska Marketing Canada Application for Modification to Alliance's New Services Offering Tariff (November 26, 2015 Letter Decision)
Compliance Filing – Modifications to Tariff

This letter decision follows from the NEB's RH-002-2014 Reasons for Decision ("RH-002-2014") which required Alliance Pipeline Ltd. ("Alliance") to report on Interruptible and Seasonal Bid Mechanics by October 7, 2015. As part of Alliance's filing on Interruptible and Seasonal Bid Mechanics, Alliance attached the Alliance Transportation Access Policy ("ATAP") setting out the processes to administer requests for services effective December 1, 2015.

In total, Alliance proposed 15 changes to its tolls and tariffs on the Alliane pipeline system. Alliance submitted that five of the changes reflect the NEB's directions in RH-002-2014 which it submitted did not require NEB approval. Alliance requested approval for the remaining 10 changes to its tariff, among which were clarifications, minor amendments, and new wording related to a ranking distinction between non-liquids and liquids receipt points. Alliance requested that these changes become effective December 1, 2015.

Tenaska Marketing Canada ("Tenaska") also applied for changes to Alliance's tariff, pursuant to section 59 of the *National Energy Board Act*. Tenaska requested changes to the scheduling and ranking of receipt point diversions and measures to prevent the use of non-public information in marketing capacity on the Alliance pipeline.

BP Canada Energy Group ULC ("BP") supported Tenaska's application, but expressed concern that the changes proposed by Alliance were material, and had not been put to Alliance's shipper task forces. BP requested that the NEB direct broader consultation processes by Alliance in order to avoid what it called "piecemeal review of the Tariff".

BP requested that the NEB approve the non-contentious tariff amendments, as well as the modifications requested by Tenaska, on an interim basis in order to provide Alliance with time to consult further with shippers.

Alliance replied stating that shippers should be entitled to rely on the terms and conditions in its tariff on a permanent basis, that it had already been actively working with its new shippers and industry stakeholders, and that the NEB need not direct any consultation.

In response to Tenaska's application, Alliance submitted that the NEB had already ruled on these matters in RH-002-2014, and that it should have been properly filed as a review and variance of the RH-002-2014 decision. Therefore Alliance requested that the NEB dismiss Tenaska's application in its entirety.

The NEB held that it would approve Alliance's tariff application and ATAP, with the exception of its proposed changes to awarding interruptible capacity, on an interim basis. The NEB noted that the application was open, via an NEB-initiated process for stakeholder comments, and only received opposing comments in respect of awarding interruptible capacity. The remaining comments were requests for clarification, which was provided by Alliance.

The NEB held that it would not approve Tenaska's application on the basis that the amendments proposed by Tenaska, such as reducing the maximum notification period for awarding new capacity to one day, were not feasible.

The NEB expressed the view that the issues raised in this application, in respect of the ATAP, the tariff, and the remaining issues for Alliance's compliance with RH-002-2014 be best addressed through consultation and negotiation between Alliance and its shippers. Accordingly, the NEB declined to rule on these issues on a final basis.

The NEB held that Alliance's consultation on its compliance filing for RH-002-2014, including the ATAP and its tariff, to be unsatisfactory. The NEB noted that the New Services Offering approved in RH-002-2014 could have unanticipated impacts, and that open consultations were of paramount importance.

Accordingly, the NEB directed Alliance to conduct consultations and negotiations with its shippers and stakeholders on a specific list of issues set out in Appendix 1 to the decision. Although it declined Tenaska's application, the NEB did include Tenaska's proposals as part of the list of issues in Appendix 1 for consultations. A copy of the issues listed in Appendix 1 can be found here, at pages 7 and 8.

Following consultations, the NEB directed Alliance to:

(a) Refile its Tariff and its compliance filing to RH-002-2014;

(b) Indicate whether it has the full support of its shippers; and

(c) Indicate where there are outstanding issues.

The NEB directed Alliance to re-file these matters on or before noon on February 1, 2016.

Accordingly, the NEB directed Alliance to file an interim tariff and interim ATAP to reflect this decision as soon as possible.

NOVA Gas Transmission Company Ltd. 2015 Meter Stations and Laterals Abandonment (Abandonment Hearing Order MHW-004-2015)
Abandonment Application

The NEB issued a hearing order after having received an application from NOVA Gas Transmission Company Ltd. ("NGTL") for leave to abandon 18 meter stations, 17 laterals and a single standalone lateral, pursuant to section 74 of the *National Energy Board Act* (the "*Project*").

The laterals and meter stations are comprised of 70.6 kilometers of gas pipeline in central and northern Alberta. NGTL proposes to remove 4.6 kilometers of pipeline, and abandon the remaining length in place. A map detailing the proposed abandonment locations for the Project can be found here.

Any person potentially affected by NGTL's application must file a letter with the NEB by February 1, 2016 setting out the following:

(a) A reference to the Notice of Abandonment Hearing;

(b) Contact information including name, mailing address, phone number and the name of the organization;

(c) Views on how they will be impacted by the Project; and

(d) Any documentation that explains or supports those views.

The NEB also established a schedule of process steps for Hearing Order MHW-004-2015 which can be found here.

The NEB noted that upon receiving submissions from parties, it may direct a further process to deal with the Project, or issue a ruling on the Project.