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DECISIONS

REGULATORY
LAW CHAMBERS

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

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

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SUPREME COURT OF CANADA

Lynne M. Quarmby, et al. v Attorney General of Canada, et al. (SCC Case Number 36353)
Leave to Appeal - Dismissed

On January 23, 2015, the Federal Court of Appeal dismissed leave to appeal the NEB Ruling #34 in the Trans-Mountain Expansion Project in Hearing OH-001-2014 (Number 14-A-62) (the "FCA Decision").

Ruling #34 denied a motion from several parties asserting that the participation decisions in Hearing OH-001-2014 infringed on the freedom of expression guarantee in section 2(b) of the *Canadian Charter of Rights and Freedoms*. A copy of the NEB's ruling can be found here.

Lynne M. Quarmby *et al*. applied to the Supreme Court of Canada for leave to appeal the FCA Decision.

The Supreme Court of Canada dismissed the motions for leave to appeal the FCA Decision with costs.

Consistent with standard practice, the Supreme Court of Canada did not provide reasons for its judgment dismissing the application.

ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission), 2015 SCC 45
Appeal – Dismissed – Standard of Review – Prudency of Costs – Reasonableness

In a unanimous decision, the Supreme Court of Canada ("SCC") dismissed the appeal of ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. (collectively, "ATCO") in respect of AUC Decision 2011-391. AUC Decision 2011-391 denied ATCO's request to recover 100 percent of the annual consumer price index ("CPI") cost of living adjustment ("COLA") amounts as part of its pension costs for 2012 (the "AUC Decision").

The AUC Decision ruled that only 50 percent of the CPI, up to a maximum COLA of 3 percent was reasonable. ATCO appealed the AUC Decision to the Alberta Court of Appeal, which was dismissed in *Atco Gas and Pipelines Ltd. v Alberta (Utilities Commission)*, 2013 ABCA 310. ATCO further appealed to the SCC, which appeal the SCC dismissed.

<u>Issues</u>

ATCO's pension plan was in a surplus position from 1996 to 2009 and no employer contributions were required during these times. However, the SCC noted, in the wake of the 2008 financial crisis, that the market value of the pension fund dropped to a shortfall position. ATCO was required to resume employer contributions in 2010.

As a result of an actuarial report, two types of employer contributions were required:

(a) Current service costs, for payments to address projected benefits to beneficiaries in 2010, 2011 and 2012; and

(b) Annual special payments to address an unfunded liability of $157.1 million across ATCO's corporate structure (including non-regulated entities).

The cost of the annual special payments attributable to ATCO was approximately $13.9 million per year. The actuarial report indexed the current service costs to account for inflation through a COLA based on the CPI, which it set at 2.25 percent for each of the three years in question.

In the AUC Decision, the AUC rejected the inclusion of the COLA amounts in light of benchmark evidence showing a wider range of COLA percentages used by other pension plans within ATCO's comparator group, mostly between 50 and 75 percent of CPI. The AUC set the allowable costs at 50 percent of CPI to a maximum of 3 percent for the COLA amounts, and reduced ATCO's revenue requirement accordingly.

The SCC noted three issues raised by ATCO on appeal:

(a) What is the standard of review;

(b) Does the regulatory framework prescribe a certain methodology in assessing whether costs are prudent; and

(c) Was it reasonable for the Commission to refuse to incorporate 100 percent of the CPI to a maximum of 3 percent into ATCO's COLA revenue requirements?

<u>Standard of Review</u>

ATCO argued that the jurisprudence favoured a standard of correctness, as ATCO framed the issues as true questions of jurisdiction (i.e. where the regulator was called on to determine whether it had the statutory authority to decide a particular question).

The SCC rejected ATCO's approach, noting that the AUC was interpreting its home statute, and as such, a standard of reasonableness is presumed. The SCC also held that the decision in question lied at the heart of the AUC's expertise of ratemaking, and was deserving of a high degree of deference. True questions of jurisdiction are rare and exceptional; the SCC noting that such a category of question may not exist at all.

Methodology for Determining Prudence

ATCO argued that the guarantee of a reasonable opportunity to recover their costs requires the AUC to examine whether the decisions to incur costs by the utility were prudent, and that a presumption of prudence applies in favour of the utility. ATCO argued that the AUC was required to apply the following prudence test:

(a) Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds;

(b) To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made;

(c) Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence; and

(d) Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time,

(the "No-Hindsight Test").

ATCO argued that the use of the word "prudent" in the *Gas Utilities Act* and the *Electric Utilities Act* mandated the use of the above No-Hindsight Test when assessing the prudence of costs.

In applying the standard of review of reasonableness, the SCC assessed whether the AUC's approach to interpreting the *Gas Utilities Act* and the *Electric Utilities Act* was reasonable. The SCC held that the meaning of "prudent" in the statue was no different than "reasonable", holding that it would not be imprudent to incur a reasonable cost, nor would it be prudent to incur an unreasonable cost. The SCC arrived at its conclusion noting the interplay between section 102 and sections 121 and 122 of the *Electric Utilities Act*.

Under section 102 of the *Electric Utilities Act*, a utility must prepare a distribution tariff for the purpose of recovering its prudent costs and apply to the AUC for approval of the same. Under sections 121 and 122 of the *Electric Utilities Act*, the AUC must consider the application to ensure that the proposed tariff is just and reasonable, and that the onus is on the applicant to establish the justness and reasonableness of the tariff.

Absent any clear inference that "prudent" is intended to refer to the No-Hindsight Test, the SCC held that prudence in the *Electric Utilities Act* should be interpreted in the ordinary meaning of the word. However, the SCC limited the application of its finding, noting that interpretations of provisions referring specifically to costs "prudently incurred", or speaking more directly to a utility's decision to incur costs at the time the decision was made, should be left for a case in which the issue arises.

The SCC made similar findings with respect to the *Gas Utilities Act*, holding that the statutory provisions do not use "prudent" to describe the decision to incur the costs, but rather they describe the costs themselves, and that no temporal reference should apply. The SCC further noted a similar statutory arrangement in the *Gas Utilities Act* in respect of the onus of establishing the justness and reasonableness of a tariff, holding that section 44(3) requires the utility to establish that the tariff is just and reasonable. The SCC also found that there were no clear inferences in the *Gas Utilities Act* to require the AUC to apply the No-Hindsight Test.

The SCC held that the statutory language indicated that the AUC was not bound to apply the No-Hindsight test, nor did a presumption of prudence apply with respect to the *Gas Utilities Act* or the *Electric Utilities Act*. Accordingly, the Court held that the AUC's interpretation of the *Electric Utilities Act* and the *Gas Utilities Act* was reasonable.

Reasonableness of the AUC's Decision

ATCO submitted that its COLA costs were committed and not forecast costs, since ATCO was bound by the *Employment Pension Plans Regulation* to make the payments. ATCO further submitted that the AUC was preoccupied in its decision with the aim of reducing rates charged to customers.

The SCC noted that although it would be axiomatic to say that if a regulator disallows a cost, that decision will be premised on the conclusion that the cost is greater than it ought to be, and leads to an inference that consumers would therefore be paying too much. However, the SCC held that this was not the same as disallowing a cost for the sole reason of consumer rates. The SCC upheld the reasonableness of the AUC Decision to disallow the COLA of 100 percent, noting that the AUC based its decision on evidence of comparator companies, and the finding that the COLA amount was not necessary for ATCO to retain and attract employees. The SCC determined that while lower rates were the result of the AUC Decision, it was not the motivating reason for the decision.

The Court accordingly dismissed the appeal on this issue.

Conclusion

In conclusion, the SCC held that while there may be situations where a failure to apply the No-Hindsight Test may result in an unjust outcome for a utility, the AUC did not act unreasonably in this case. The SCC held that the disallowed costs were forecast costs, and the AUC did not apply an impermissible methodology. As a result, the direction to reduce the annual COLA to 50 percent of CPI, to a maximum of 3 percent, was not unreasonable.

The SCC dismissed the appeal.

Ontario (Energy Board) v Ontario Power Generation Inc., 2015 SCC 44
Appeal – Allowed – Standard of Review – Reasonableness – Tribunal Role on Appeal

Ontario Power Generation Inc. ("OPGI") applied to the Ontario Energy Board ("OEB") for certain payment amounts as part of its rate application covering the 2011-2012 period.

In its Decision, the OEB disallowed $145 million in labour compensation costs related to OPGI's nuclear operations. The OPGI's labour costs were found to be out of step with its peers in the regulated power generation industry (the "OEB Decision").

OPGI appealed the OEB Decision to the Ontario Divisional Court – which dismissed the appeal – and to the Ontario Court of Appeal, which set aside the decisions of the Ontario Divisional Court and the OEB and remitted the matter back to the OEB for redetermination. The OEB appealed the Ontario Court of Appeal's decision to the Supreme Court of Canada ("SCC").

Issues

OPGI's labour costs were, as the SCC noted, comprised of collective agreements entered into by OPGI and two of its unions. OPGI is Ontario's largest energy generator, and employs approximately 10,000 people in connection with its regulated facilities, 95 percent of whom were noted to work in its nuclear energy business. The SCC noted that approximately 90 percent of OPGI's employees are unionized under the Power Workers' Union, Canadian Union of Public Employees, Local 1000 ("PWU") and the Society of Energy Professionals ("SEP").

OPGI requested a revenue requirement of $6.9 billion, a 6.2 percent increase over its prior revenue requirement. Approximately $2.8 billion in costs pertained to compensation, $2.4 billion of which was attributable to labour costs of OPGI's nuclear business. The SCC discussed how these costs were fixed by OPGI's collective agreements with PWU and SEP from April 2009 through March 2012. These collective agreements provided for annual wage increases between two and three percent.

The SCC identified the following issues on appeal:

(a) What is the appropriate standard of review?

(b) Was the OEB Decision to disallow $145 million of OPGI's revenue requirement reasonable? and

(c) Did the OEB act impermissibly in pursuing its appeal in this case?

Standard of Review

The Court's findings on the appropriate standard of review were brief, as neither party disputed that the appropriate standard of review was reasonableness.

Reasonableness of the OEB Decision: Choice of Methodology and Characterization of Costs

The SCC found that the OEB must ensure it regulates with an eye to balancing both consumer interest and the efficiency and financial viability of the electricity industry. As part of this function, Section 78.1(5) of the *Ontario Energy Board Act* (the "*OEB Act*") empowers the OEB to fix payment amounts it finds to be just and reasonable in exchange for the provision of service. The SCC noted that Section 78.1(6) of the *OEB Act* places the burden of proof on the applicant for establishing the justness and reasonableness of its costs.

The SCC held that such a statutory scheme meant that the utility must, over the long run, be given the opportunity to recover, through its permitted rates, its operating and capital costs. The SCC noted that this case primarily dealt with operating costs. However, the SCC pointed out that this did not mean that the OEB was obligated to accept every cost submitted by a utility, as a utility must still satisfy the OEB of the justness and reasonableness of the amounts it is claiming. In the event that a utility's costs are disallowed, the utility may either forego those costs, or if it cannot be foregone, the shareholders will have to absorb the reduction through a lower return on investment.

The SCC also pointed out that the *OEB Act* does not specifically describe any methodology that the OEB is required to adopt, nor does it expressly apply any presumption of prudence. Further, the Court found that section 6(1) of the *Ontario Regulation*, 53/05 (the "*Ontario Regulation*") expressly allows the OEB to establish a methodology in setting rates. Only in section 6(2)(4.1) of the *Ontario Regulation* does the statutory scheme impose a specific methodology, which the SCC noted applied only to financial commitments and costs prudently incurred in the course of planning for the development of proposed new nuclear generation facilities.

With respect to characterization of costs, the OEB used two types of costs examination on the utility's expenditures:

(a) Forecast costs, which the utility has estimated for a future period and which can be reduced or avoided; and

(b) Committed costs, for which there is no opportunity for the utility to take action to reduce.

The OEB explained that the onus was on the utility to demonstrate that its forecast costs were just and reasonable.

The SCC held that the labour compensation costs, which caused the $145 million disallowance, were partly composed of committed costs, and party composed of forecast costs, or costs that were subject to management discretion. The majority, though it agreed with OPGI that it was unreasonable to treat the costs as entirely forecast, held that the OEB was not bound to apply any particular prudence test in evaluating such compensation costs.

The SCC distinguished the Ontario Court of Appeal's formulation of the No-Hindsight Test, noting that the question of whether the prudence test was a required feature of just-and-reasonable ratemaking was not squarely before the SCC in that instance. The SCC found that the parties had rather agreed "on the general approach the Board should take to reviewing the prudence of a utility's decision." The question before the Ontario Court of Appeal in that instance was whether the OEB had reasonably applied that agreed-upon approach. Therefore the cases considering the No-Hindsight Test were, in the SCC's determination, disputes over the application of the No-Hindsight Test where there was no dispute over whether an alternative methodology could reasonably have been applied. In those cases the parties adopted that test by agreement, the court didn't actually find that applying the No-Hindsight Test was a requirement.

While the SCC noted that the No-Hindsight Test was widely applied and accepted by regulators, it found no support in the statutory scheme of the *OEB Act* that compelled or required its application to questions of rate-making. The SCC held that where the statue only requires the regulator to set just and reasonable rates, the regulator may make use of a variety of analytical tools in assessing the utility's proposed rates. In this case, the SCC held that, not only did the OEB have the discretion to set the methodology; it was expressly allowed to do so pursuant to the *Ontario Regulation*, section 6(1).

Given the previous findings that the costs were at least partly committed, the SCC held that the OEB did not act improperly in disallowing the compensation costs. Part of the Court's analysis hinged on the nature of the costs as operation costs, not capital costs. Capital costs typically entail some amount of risk, and are not always necessary for the short-term production of the utility. The SCC noted that such costs, however, are frequently wise investments for the utility's long term viability. Therefore, the SCC found that the No-Hindsight Test (with or without a presumption of prudence) may play an important role in ensuring that utilities are not discouraged from making investments in the development of their facilities. In contrast, operating costs were, in the SCC's opinion, is different from capital costs. There would be little danger of discouraging utilities to incur operating costs, as they are frequently an inescapable element of operating a utility. While the SCC discussed that the OEB Decision may have the effect of making utilities such as OPGI more hesitant about committing to high compensation costs, the SCC noted that was precisely the intended effect. The recurring nature of the costs suggested that the disallowance was not targeted exclusively at committed costs alone, but rather with respect to the total compensation costs in aggregate.

<u>Permissibility of OEB Appeal</u>

Rothstein J., writing for the majority, discussed a tribunal's role on appeal. Rothstein J. noted a board's statutory right to be heard on judicial appeal was typically limited in scope on the submissions it could make to matters such as jurisdiction, standard of review and a general explanatory role. However, the majority noted that the Supreme Court has allowed boards and tribunals to participate fully in several matters without making any comment on the appropriateness of the board's role.

The SCC identified two common law restrictions on the scope of a tribunal's participation on appeal from its own decision (citing *Canada (Attorney General) v. Quadrini*): finality and impartiality.

With respect to finality, a tribunal may not speak on a matter once it has provided its reasons for decision. With respect to impartiality, concerns arise due to the fact that some cases are remitted to the tribunal itself for reconsideration. However, the SCC found that these two restrictions did not amount to a categorical ban, but rather "fundamental concerns" to address in creating a discretionary approach. This, in the SCC's analysis, would provide the best means of ensuring that finality and impartiality are respected without depriving the courts of useful and important information. The Court developed a non-exhaustive list of factors for determining the appropriate level of participation for a tribunal:

(a) If an appeal were otherwise unopposed, a reviewing court may benefit by exercising its discretion to grant the tribunal standing;

(b) If other parties are available to oppose an appeal or review, and can fully respond to arguments, tribunal standing is less important in ensuring a just outcome; and

(c) The nature of the tribunal as either an arbiter of conflicts between parties, or whether it serves a policy-making, investigative or regulatory role in the public interest, will serve as a factor on the degree to which impartiality concerns are raised.

The majority held that the OEB's participation in the appeal was not improper, noting:

(a) The expertise of the OEB in rate-setting;

(b) Its mandate to act in the public interest;

(c) The lack of any designated utility consumer advocate; and

(d) The position of the OEB as the only party in opposition to the party challenging the decision.

The SCC concluded that the introduction of arguments by a tribunal on appeal that interpret, or were implicit in, the original decision did not offend the principle of impartiality. In the same vein, the SCC held that it would not offend the principle of finality to permit a tribunal to explain its policies and practices to the SCC, especially if in response to arguments raised by a counterparty.

However, the SCC tempered its findings on this issue, cautioning that tribunals do not have an unfettered ability to raise new arguments on appeal.

<u>Conclusion</u>

In the result, the majority allowed the appeal, set aside the decision of the Ontario Court of Appeal, and reinstated the OEB Decision.

ALBERTA COURT OF APPEAL

FortisAlberta Inc. v Alberta (Utilities Commission), 2015 ABCA 295
Appeal – Dismissed – Risk of Stranded Assets - Procedure

ENMAX Power Corporation, ATCO Gas and Pipelines and ATCO Electric Ltd., AltaGas Utilities Inc., EPCOR Distribution & Transmission Inc., FortisAlberta Inc., and AltaLink Management Ltd., in its capacity as general partner of AltaLink, L.P. (collectively, the "Utilities") appealed two decisions of the AUC to the Alberta Court of Appeal (the "ABCA"):

(a) Decision 2013-417, known as the Utilities Asset Disposition decision, wherein the AUC held that the risk of stranded assets should be borne by utility shareholders rather than be retained in rate base and paid for by ratepayers (the UAD Decision"); and

(b) Decision 2011-474, known as the Generic Cost of Capital decision, with respect to which the Utilities raised concerns regarding the procedural aspects of the decision (the "GCOC Decision").

<u>UAD Decision Appeal</u>

With respect to the UAD Decision, the ABCA described three developments that were of relevance to Alberta utility regulation:

(a) Issues of stranded assets, as well as the nature of and various treatments of stranded assets;

(b) The scope and effect of the Supreme Court of Canada ("SCC") *Stores Block* case (2006 SCC 4) ("*Stores Block*") relating to the power of the AUC in dealing with asset dispositions; and

(c) The deregulation of the electricity sector in Alberta.

The ABCA described stranded assets as any assets that have lost their usefulness before the end of their expected economic life. Such assets are not yet fully depreciated, and are no longer capable of being used. The ABCA indicated that stranded assets fell into a broader category of "stranded costs", where the expected revenues from ratepayers are insufficient to cover a utility's operating costs and to provide a fair return on investment.

The stranded assets at issue before the ABCA were because of extraordinary and unanticipated events, such as flood, fire and early obsolescence.

In the *Stores Block* decision, the SCC held that all gains and all losses arising on an extraordinary disposition were solely on account of the utility, and not to ratepayers. The SCC found that the 'regulatory compact' did not translate into a property right for ratepayers to the underlying assets of the utility, meaning that none of the gains on any asset sale could be allocated to ratepayers.

The AUC was subsequently faced with a number of conflicting interpretations of how to apply *Stores Block* in the context of its own regulatory mandate. The AUC had initiated the UAD proceeding to consider the disposition of assets in the wake of the *Stores Block* decision.

In this decision, the ABCA also summarized the deregulation of the electricity market in Alberta. The ABCA noted that the treatment of plants built under the previous regulatory model was the subject of debate, which culminated in the *Electric Utilities Amendment Act* in 1998. This amendment introduced Power Purchase Arrangements ("PPA") to overcome the concentration of market power and to create competition by having existing power producers sell the output of their regulated generating units under PPAs.

Standard of Review

In dealing with the standard of review, the ABCA determined that since the AUC was interpreting its own home statute, a presumption of deference to the decision-maker's interpretation applied. The ABCA held that there was little argument that the AUC possessed expertise in the area of rate-setting and utility regulation. The ABCA canvassed possible exceptions to this presumption, noting that the presumption can be overturned:

(a) Through a contextual analysis; or

(b) If the question warrants a review on the correctness standard, either as a question of law of central importance to the legal system, or a true question of jurisdiction.

The ABCA determined that the appeals did not raise a question of jurisdiction and noted that this power was well within the expertise of the AUC, and indeed central to its mandate.

The ABCA held that it would review the decisions under appeal on a standard of reasonableness. This was due to the fact that the issue before the ABCA was not whether the interpretation being urged by the Utilities was reasonable, but whether the approach adopted by the AUC was unreasonable.

Central Issues and ABCA Rulings

The ABCA described the central issue in the UAD Decision as a consideration of who bears the loss on assets that are not fully depreciated if rendered unusable as a result of unanticipated events.

In following the SCC's determinations in *Stores Block*, the AUC determined in the UAD Decision, that all stranded assets would be to the account of the utility and not the ratepayers.

The ABCA summarized the AUC's findings as follows:

(a) *Stores Block* also applies to dispositions in the ordinary course of business. To hold otherwise would amount to a finding that customers have acquired a property interest in the assets, contrary to the findings in *Stores Block*;

(b) Assets can only remain in rate base if they are used or required to be used to provide service. If an asset is no longer used, it must be removed from rate base;

(c) The AUC's depreciation practices using mass property accounts was consistent with *Stores Block*, as the depreciation methods remove depreciable assets that are no longer used or required to be used to provide utility service from rate base and customer rates; and

(d) Any assets that cease to be used or required to be used prior to the end of its economic life (i.e. not fully depreciated) must be removed from rate base as an extraordinary retirement for the account of the utility, and not ratepayers.

The Utilities argued that the AUC's conclusions in the UAD Decision for gas utilities would prevent them from fully recovering their prudently incurred costs, and therefore must be restricted to assets disposed of outside the ordinary course of business.

The Utilities further submitted that the UAD Decision, as it applied to electric utilities, inappropriately relied on *Stores Block*, which applied to regulated gas utilities. The Utilities submitted that the electrical regulatory regime was fundamentally distinct from the gas regulatory regime, and that *Stores Block* and subsequent decisions therefore did not apply.

With respect to the UAD Decision as it applies to gas utilities, the Utilities argued that the regulatory compact, as reflected throughout the statutory regime, entitled them to a return on their prudent capital investment and a return of all prudent capital investment in all circumstances.

The Utilities submitted that the "used or useful" criterion for assets remaining in rate base applied only to the calculation of a reasonable return on investment. In contrast, the Utilities submitted that the return of prudent capital investment was an absolute requirement under section 36 of the *Gas Utilities Act* (the "*GUA*"). The Utilities further relied on section 4(3) of the *Rules, Relationships and Responsibilities Regulation*, in that a gas distributor is entitled to recover in its tariffs the prudent costs, as determined by the AUC, of the gas distributor in carrying out its obligations.

The ABCA held that it did not read the language of the *GUA* to require the guaranteed cost recovery as advocated for by the Utilities. The ABCA found that the distinction that the Utilities attempted to draw was not dictated by the plain language of section 36 of the *GUA*. The ABCA also relied upon a contextual reading of sections 36 and 37 of the *GUA* together as giving the AUC a mandate to fix just and reasonable rates for the utility service received. The ABCA held that there is no absolute obligation for ratepayers to continue to pay for a service that they are not actually receiving.

The ABCA determined that the statutory framework for utility regulation in Alberta does not dictate only a single possible solution to the problem of stranded assets, as argued by the Utilities.

The ABCA described the Utilities' view of the 'regulatory compact' as overbroad, noting that the regulatory compact offers an opportunity to earn a reasonable return on prudent investment, and to recover its prudently incurred expenses. The ABCA further rejected the argument that that UAD Decision was confiscatory, finding that public utilities are protected against the arbitrary acts of commissions, but not from normal course business hazards or other economic forces. The AUC, in the ABCA's holding, struck a symmetrical approach to extraordinary retirements, allowing the utility shareholder to exclusively benefit from, and bear the risks of, any gain or loss in keeping with the *Stores Block* decision.

The ABCA also found that it is the Utilities that estimate the future useful life of their assets in applying for their respective revenue requirements. The AUC in turn uses these estimates as a key factor in evaluating whether such costs are prudent in fixing just and reasonable rates, and such a statutory role was not, in the ABCA's view, usurped by any guarantee of a return of all investments in all circumstances.

With respect to the Utilities' submissions that *Stores Block* arose in the context of gas utility regulation, and that the AUC's UAD Decision failed to account for the historic and legislative differences between electric utilities and gas utilities, the Utilities submitted that unlike the *Gas Utilities*

Act, the *Electric Utilities Act* makes no mention of rate base assets being "used or required to be used" in order to provide service. The Utilities submitted that this was a clear and express statement that the legislature did not intend that assets must be "used or required to be used" in order to be included in an electric utility's tariff. Therefore, the Utilities argued that once the AUC deemed a cost to have been prudently incurred, the electric utility in question was thereby entitled to a full recovery of that cost, even if the asset is no longer used in the provision of service.

The ABCA canvassed the *Electric Utilities Act*, and found that under section 122, the AUC similarly reviews tariffs proposed by a utility to ensure that the tariff is just and reasonable, and not unduly preferential, arbitrarily or unjustly discriminatory.

The ABCA noted that, taking into account the legislative history and context alone, and disregarding the *Stores Block* decision, the interpretation advanced by the Utilities was permissible. However, in order for the Utilities to be successful on appeal, the question is not whether their preferred interpretation was permissible, but whether it was the only such permissible interpretation.

The ABCA held that the interpretation advanced by the Utilities was not the only permissible interpretation. The determination of the scope of allowable cost recovery was plainly within the AUC's purview, and the legislation did not operate to remove any discretion of the AUC to deny any cost recovery. The *Electric Utilities Act* permitted the recovery of prudently incurred costs, but did not mandate it. Therefore, there exists no guarantee of prudent cost recovery, whether implicit or explicit in the *Electric Utilities Act*.

The ABCA also relied on the Utilities' concession that any gains from assets disposed of outside the ordinary course should be solely for the benefit of the utility, indicating a reliance on the principles of *Stores Block*, but only for the gains on asset dispositions. Consequently, the ABCA found that the AUC's parallel approach to gains and losses in this context was entirely reasonable.

In the result, the ABCA held that the AUC's approach to, and application of, *Stores Block* was reasonable and well within the AUC's statutory authority. The AUC's decision in respect of the legislation and law in Alberta was reasonable. Therefore, the ABCA denied the Utilities' appeal of the UAD Decision, and upheld the AUC's findings as reasonable.

<u>GCOC Decision</u>

The Utilities filed a second set of appeals relating to the GCOC Decision. The Utilities argued that there was a lack of procedural fairness in relation to the AUC's handling of the proceeding, as the AUC made a finding that stranded assets should not remain in rate base, regardless of the reason for having been stranded. The Utilities submitted that they were not given sufficient opportunity to provide evidence and submission on the impact of the conclusion on stranded assets contained in the UAD Decision with respect to calculating a fair return for 2011 and 2012.

The ABCA determined that the AUC exercised its authority to choose its own procedures, and in this instance took specific procedural steps to provide parties the opportunity to make submissions on stranded asset risk and its effect on return on equity. Accordingly, the ABCA saw nothing to support the notion that the Utilities were somehow unaware that stranded asset risk would be affected by the issues under consideration in the GCOC Decision.

<u>Conclusion</u>

The Court dismissed the Utilities' appeals of both the UAD Decision and the GCOC Decision.

ALBERTA ENERGY REGULATOR

Grand Rapids Pipeline GP Ltd. Consideration of Grand Rapids' Compliance with Conditions 12 and 13 of Decision 2014-012 (2015 ABAER 004)

Compliance – Routing Superiority

Grand Rapids Pipeline GP Ltd., a company jointly owned by TransCanada PipeLines Limited and Phoenix Energy Holdings Limited ("Grand Rapids"), previously applied to the AER for approval to construct, operate and reclaim the Grand Rapids pipeline project. The project consisted of two transmission pipelines, two smaller diameter lateral pipelines, three pump stations, and three terminals (the "Project"). The AER approved the Project in Decision 2014 ABAER 012, subject to 26 conditions, arising in part from concerns expressed by Fort Industrial Estates Ltd. ("Fort Industrial"), as well as D&A Guenette Farms Ltd. ("Guenette").

The panel that considered the Project (the "Panel") remained constituted to consider Grand Rapids' compliance with Conditions 12 and 13 set out in Decision 2014 ABAER 012.

Condition 12 of Decision 2014 ABAER 012 required Grand Rapids not to construct or carry out any incidental activities to construction, between NE 7-055-21W4M and SE 6-054-22W4M, unless Grand Rapids satisfied the panel that the applied for route is the superior route. Condition 12 also required Grand Rapids to develop at least one alternative route that avoids both the Fort Industrial lands on 1-055-22W4M and the lands within the city of Fort Saskatchewan, and apply to the panel for review of the alternative route ("Condition 12").

Condition 13 of Decision 2014 ABAER 012 was substantially similar, but required Grand Rapids to develop at least one alternative route that avoids both the Guenette lands on the south half of 34-054-22W4M, NW 27-054-22W4M, and NE 28-054-22W4M, and apply to the panel for review of the alternative route ("Condition 13").

On June 8, 2015, Grand Rapids provided alternative routing for the Project to the AER.

Prior to the beginning of the hearing, Fort Industrial withdrew from the hearing. However, the AER determined that it was still required to consider Grand Rapids' compliance with both conditions. The AER held that the two issues it would consider were:

(a) Has Grand Rapids satisfied the requirements of Condition 12 and Condition 13; and

(b) Has Grand Rapids convinced the panel that the applied-for route is the superior and most suitable route? Or alternatively, are any of the alternative routes superior to the applied-for route?

Requirements to Meet Condition 12 and Condition 13

The AER assessed Grand Rapids' compliance with Condition 12 and Condition 13 by addressing the three components of each condition, namely;

(a) Did Grand Rapids conduct an analysis of at least one alternative pipeline route that it is prepared to construct, that avoids the Fort Industrial Estates Ltd. and Guenette lands and the lands within the city of Fort Saskatchewan ("Requirement 1");

(b) Did the analysis include a comparison of the identified alternative routes with the applied-for route ("Requirement 2"); and

(c) Did the analysis include detailed information about any stakeholder concerns ("Requirement 3")?

Grand Rapids identified five potential alternative routes in its application to the AER, but noted that it was only prepared to construct two of the routes:

(a) Alternative route 1, a route which Grand Rapids submitted did not meet the requirements, since it crossed the Fort Industrial Estates Ltd. and Guenette lands, as well as lands within Fort Saskatchewan ("Route 1"); and

(b) Alternative route 2, a route which Grand Rapids submitted avoided the Fort Industrial Estates Ltd. lands, Guenette lands, and avoided lands within Fort Saskatchewan ("Route 2").

The AER held that Route 1 did not meet Requirement 1, but that Route 2 did meet Requirement 1.

Grand Rapids submitted that it compared the alternative routes to the applied-for route using a 10 point route selection criteria. The AER determined that Grand Rapids met Requirement 2, in providing a qualitative and quantitative comparison of the identified alternative routes with the applied-for route.

Grand Rapids submitted that it provided information in respect of landowner concerns and stakeholder consultation regarding its alternative routes. The AER determined that Grand Rapids provided sufficient stakeholder and landowner concerns to comply with Requirement 3.

Route Superiority

Grand Rapids provided submissions to the AER that its previous decisions were less onerous than the conditions set out in Decision 2014 ABAER 012. Grand Rapids noted that Decision 2010-022 from the AER's predecessor, the Energy Resources Conservation Board, indicated that applications are not required to show that their applied-for or preferred routes are superior to any possible alternative routes. Grand Rapids submitted that its applied-for route should not be rejected unless an alternative route was determined to be demonstrably better.

The AER rejected Grand Rapids' submission on the basis that it was not bound by previous decisions, and that the panel expressed concern in Decision 2014 ABAER 012 that Grand Rapids had not provided qualitative and quantitative comparison of the applied-for route in comparison to alternatives. The AER held that the onus was on Grand Rapids to demonstrate the superiority of the applied-for route in Decision 2014 ABAER 012.

As indicated above, Grand Rapids submitted that it considered 10 criteria for its route selection. The AER noted that the *Responsible Energy Development Act* does not specify any criteria for project proponents to use in route planning or comparing alternative routes. The AER cautioned that no single set of routing criteria can be universally applied, and were therefore dependent on the particular facts.

Given the factors that the AER must consider under section 3 of the *Responsible Energy Development Act General Regulation*, the AER held that the following selected criteria was appropriate in the context of this particular application:

(a) Observe project control points;

(b) Minimize, considering other route selection objectives, the total route length;

(c) Consider operational factors such as maintenance access, power availability, and pipeline integrity;

(d) Follow existing linear disturbances wherever possible;

(e) Minimize impact on landowners, aboriginal communities, and other stakeholders;

(f) Minimize the number of watercourse and wetland crossings;

(g) Minimize the impact on the environment and sensitive environmental receptors;

(h) Avoid park lands, cemeteries, historical sites, and archeological sites;

(i) Avoid known ceremonial, spiritual, habitation, and resource-gathering sites;

(j) Comply with existing land use plans and setbacks; and

(k) Include hydraulic design, constructability, and cost considerations,

(the "Criteria").

Having established the Criteria for assessing the pipeline routes for the Project, the AER considered whether any of the alternative routes were superior to the applied-for route and made the following findings:

(a) Observe project control points: the panel found that this criterion was not a differentiating factor, as all the routes considered had the same control points;

(b) Minimize, considering other route selection objectives, the total route length: The applied-for route was 14.4 km long, while Route 1 was 14.5 km and Route 2 was 15.8 km. The AER considered that the differences were not significant given the 460 km total length of the Project. The AER concluded that due to the additional length, right-of-way and temporary workspace required for Route 1 and Route 2, the alternative routes were not superior to the applied-for route;

(c) Consider operational factors such as maintenance access, power availability, and pipeline integrity: The AER held that, since there were no pump stations or other facilities requiring power along the proposed routes, this was not a differentiating criterion;

(d) Follow existing linear disturbances wherever possible: The AER determined that the applied-for route paralleled existing linear disturbances for 94% of its route, while Route 1 and Route 2 paralleled existing linear disturbances for 98% of their respective routes. Given that all three proposed routes almost exclusively followed existing linear disturbances, the AER again concluded that this criterion was not a significant differentiator between the proposed routes;

(e) Minimize impact on landowners, aboriginal communities, and other stakeholders: The AER found that all of the lands under each of the proposed routes were privately held, and thus no aboriginal or other community stakeholder concerns were identified. Grand Rapids submitted that 20 of the 21 landowners had no objections to the applied-for route or Route 1, with the exception of Guenette, who opposed both. Guenette explained that the pipeline corridor on its lands was effectively "full". And that any further pipeline development on its lands would negatively affect its property values.

The AER noted that Guenette did not appear to differentiate its opposition to either the applied-for route or Route 1. The AER held that the applied-for route would increase the right-of-way on Guenette's lands by 5.05 hectares, an increase of 20 percent, which it found was not insignificant.

With respect to stakeholder support for Route 2, Grand Rapids submitted that it considered approximately 18 of the 25 landowners on the route as moderately or highly likely to oppose the project and file a statement of concern.

Given the extensive consultation that Grand Rapids undertook for the applied-for route, including proposed mitigation, in contrast with the relatively new alternative routes, the AER agreed it was difficult to compare the level of stakeholder support for each route. However, the AER determined that based on the evidence, there was clearly more support for the applied-for route than the alternative routes. On this basis, the AER determined that neither Route 1 nor Route 2 were superior to the applied-for route.

(f) Minimize the Number of Watercourse and Wetland Crossings: The AER held that the number of watercourse crossings was not a significant differentiator between the routes, as each of the routes crossed Ross Creek, while the remaining crossings were minor tributaries, drainage ditches, or low-lying areas to facilitate drainage during run-off. The AER also held that the number of wetlands was not a significant differentiator, as most of the wetlands along the routes were classified as marsh or swamp within highly developed or pre-disturbed areas. The AER determined that neither Route 1 nor Route 2 were clearly superior to the applied-for route based on the number of watercourse and wetland crossings.

(g) Minimize Impact on the Environment and Sensitive Environmental Receptors: The AER determined that aside from watercourses and wetlands, no other environmentally sensitive features differentiated the various alternative routes, and that on this criterion, none of the routes were clearly superior.

(h) Avoid Park Lands, Cemeteries, Historical Sites, and Archaeological Sites: The AER determined that there were no identified park lands, cemeteries, historical sites, archaeological sites or other cultural sites along the applied-for route, Route 1 or Route 2, and was not a significant differentiating factor.

(i) Avoid Known Ceremonial, Spiritual, Habitation, and Resource Gathering Sites: As the entirety of the applied-for route, Route 1 and Route 2 were entirely located on privately owned lands, the AER held that there were no identified ceremonial, spiritual, habitation, or resource gathering sites along any of the routes.

(j) Comply with Existing Land Use Plans and Setbacks: The Panel identified the following land use documents and plans as relevant to its review of Grand Rapids' proposed and alternative routes:

(i) The Regional Energy Corridors Policy Framework;

(ii) Fort Saskatchewan Municipal Development Plan and Land Use Bylaw;

(iii) Josephburg North Industrial Area Structure Plan; and

(iv) Strathcona County Municipal Development Plan and Land Use Bylaw.

The AER found that the applied-for route and Route 1 complied with the relevant land use plans and zoning for the area. The AER noted that Route 2 also complied with the relevant land use plans and zoning for the area, and would result in less potential for land use conflict with an urban area, given its distance from urban areas. However, the AER found that there was potential for conflict with a proposed large scale gravel extraction project on Route 2. Given the above findings, the AER concluded that all three of the routes were acceptable from a land use planning perspective, and accordingly that none of the routes were clearly superior.

(k) Hydraulic Design, Constructability, and Cost Considerations: The AER held that costs are a valid consideration in evaluating competing route alternatives. However, the AER also found merit to the submissions made by Guenette that sunk costs are an inappropriate metric to justify one route as superior to another. The AER noted that Grand Rapids did not submit detailed cost estimates, and held that it was not able to determine which route was superior from a cost perspective.

The AER determined that the number of crossings alone was not determinative of a superior route for this criterion, but did find that Route 2 posed fewer constructability issues. The AER concluded that routing analyses are challenging, and noted that it was difficult to satisfy all stakeholders in selecting a route.

Conclusion

The AER found that the following three criteria were the most relevant and useful in its analysis:

(i) Criteria (e) – Minimizing the impact on landowners and aboriginal communities;

(ii) Criteria (f) - Minimizing the number of watercourse and wetland crossings; and

(iii) Criteria (j) - Compliance with existing land use plans.

Accordingly, the AER placed significant weight on its determinations for each of the above criteria.

The AER summarized its findings, in holding that neither Route 1 nor Route 2 were superior to the applied-for route. Accordingly, the AER ordered Grand Rapids to proceed with construction of the applied-for route.

Decision to Issue a Declaration Naming an Individual Pursuant to Section 106 of the Oil and Gas Conservation Act (2015 ABAER 005)
Naming Declaration – Compliance Assurance

In January 2015, the liability management ("LM") staff at the AER provided a recommendation for the AER to issue a declaration naming an individual pursuant to section 106 of the *Oil and Gas Conservation Act* ("*OCGA*").

The LM alleged that the individual was in control of three different companies:

(a) Copper Creek Petroleum Inc. ("Copper Creek");

(b) Reid Resources Inc. ("Reid Resources"); and

(c) Savant Energy Ltd. ("Savant"),

(collectively, the "Licensees").

The LM also alleged that the Licensees failed to comply with a total of 18 orders issued by the AER over a period of three years beginning in 2010.

The LM submitted that it followed the requirements set out in *Directive 019: Compliance Assurance* by giving notice to the operator at the time of the identification of the noncompliance. Following failure to address the situation to the AER's satisfaction, the AER issued a number of escalating enforcement actions, including fees, penalties, suspensions and abandonment orders.

The AER described the test for a decision to issue a declaration naming an individual under section 106 of the *OCGA* as a two-step test:

(a) Section 106(1) requires that the licensee, approval holder, or working interest participant contravene or fail to comply with an order of the AER or has an outstanding debt to the AER; and

(b) Section 106(2) requires the AER to give the person who may be named at least ten days to show cause why they should not be named.

The AER noted that section 106 of the *OGCA* is a reverse onus provision, and requires the AER to balance the public interest, while ensuring public fairness. Therefore, once the LM established a *prima facie* case, the onus shifted to the individual to show why the declaration and order under section 106 of the *OCGA* should not be made.

The AER noted that the individual provided no evidence to show cause why the declaration should not be made, and that he was given ample time to do so, including a time extension at the individual's request. The AER found that the procedural history showed the individual was provided more than ample opportunity to know the case against him and respond under section 106(2) of the *OCGA.* The individual failed to respond in any meaningful way to the allegations made by the LM.

Accordingly, the AER cancelled the hearing, and proceeded to issue a declaration on the basis of the evidence submitted by the LM.

The AER considered the following issues, each as elements of the test for issuing a declaration under section 106 of the *OGCA*:

(a) Were there contraventions of or failures to comply with AER orders ("Issue 1");

(b) If there was a contravention or failure, was the individual a director, officer, or other person in direct or indirect control of the relevant company at the relevant time ("Issue 2"); and

(c) If there was a contravention or failure, and the individual was in control, is the requested declaration and order in the public interest ("Issue 3")?

Since the individual failed to file evidence to rebut the *prima facie* case established by LM, the AER panel considered whether the evidence filed by the LM satisfied the *OGCA* section 106 test on a balance of probabilities.

Issue 1

With respect to whether the individual contravened or failed to comply with AER orders, the LM submitted copies of 18 orders issued to the Licensees between 2010 and 2013.

Accordingly, the AER determined that there were 18 orders from the AER that the Licensees failed to comply with: 6 to Copper Creek; 10 to Savant; and 2 to Reid Resources.

Issue 2

With respect to whether the individual was directly or indirectly in control of the Licensees, the AER noted that the control in question must be the authority to cause the Licensees to meet their respective financial obligations to the AER and to comply with AER orders, regardless of title or position. The AER described such a description of control as being consistent with section 101(1) of the *Alberta Business Corporations Act* (the "*AB Corp. Act*"). Section 101(1) of the *AB Corp. Act* provides that the directors must manage or supervise the management of the business and affairs of a corporation, unless there is a unanimous shareholder agreement otherwise.

The LM submitted that each of the Licensees were Alberta corporations. The LM provided evidence that the individual was the sole director of each of the Licensees, as well as the president of Copper Creek at the relevant times that the orders were issued. The LM provided evidence that the sole shareholder of Savant was Reid Resources. In turn, Reid Resources was wholly owned by both the Family Trust, which the LM submitted the individual was involved in, and an individual, whom the LM submitted the individual was related to. The LM also submitted that the individual was the sole shareholder of Copper Creek.

Without any evidence of a unanimous shareholder agreement to the contrary, the AER found that the LM had provided *prima facie* evidence of control of the Licensees by the individual. Since section 106 of the *OGCA* is a reverse onus provision, and noting that the individual did not provide evidence, the AER held that the individual was, on a balance of probabilities, in control of the Licensees at the relevant times.

Issue 3

With respect to public interest considerations, the LM submitted that the AER had previously articulated its view of the public interest elements of section 106 of the *OGCA* in Decision 2006-006. The LM quoted the AER's predecessor as stating in Decision 2006-006: "to prevent a licensee or person in control of a licensee from continuing to breach EUB requirements or Board orders or from incurring abandonment costs or incurring new breaches or additional debts."

The LM submitted that approximately $430,389.00 had been spent to abandon the Licensees' wells and pipelines, noting that the remaining seven wells, one facility and two pipeline segments remain suspended and are awaiting abandonment.

The AER held that it was in the public interest to name the individual under section 106 of the *OGCA.* A failure to sanction the individual's behaviour would undermine the credibility of the regulatory and enforcement processes of the AER. Noncompliant conduct should be deterred.

The LM requested certain terms be included in the declaration naming the individual. However, the AER rejected the LM's proposed terms on the basis that such terms would amount to a ban on the individual's involvement in or with companies that hold, require, or seek to acquire any licence or approval from the AER.

The AER instead preferred to incent the individual to address impacts resulting from noncompliances and demonstrate an ability to be a responsible operator. Therefore, the AER set terms in Appendix 2 of its decision, available here.

The AER held that the terms in Appendix 2 of the decision would:

(a) Advance the public interest;

(b) Incent the individual to address impacts resulting from the non-compliances;

(c) Publicly name the individual so that others in the business or who may consider doing business with him can make an informed decision whether to involve him or not and in what way; and

(d) Enable the AER to manage the risk posed by the individual being in control of an entity involved in regulated energy resource activities.

A full listing of the well licences, facility licences and pipeline licences affected by this decision can be found in Appendix 1 of the decision, available here.

Update on Restrictions to Temporary Diversion Licences (Bulletin 2015-26)
Bulletin – Temporary Diversion Licences

The AER announced Bulletin 2015-26 as an update to the previous *Bulletin 2015-25: Restrictions to Temporary Diversion Licences*, which imposed restrictions on temporary diversion licences ("TDL") for flowing watercourses. Due to the recent rainfall and cooler weather, the AER provided the updates for the following watercourse basins:

(a) Battle River basin – No change, no TDL applications are being accepted;

(b) South Saskatchewan River Basin – no TDL applications are being accepted for specific water courses. The restriction on Sheep River has been lifted;

(c) Milk River basin - No change, no TDL applications are being accepted;

(d) Peace River basin - No change, no TDL applications are being accepted;

(e) Athabasca River basin – no TDL applications are being accepted for watercourses upstream of the town of Athabasca, except for the Athabasca River, which is no longer restricted; and

(f) North Saskatchewan River basin - No change, no TDL applications are being accepted.

A map of current water restrictions can be found on the Alberta Environment and Sustainable Resource Development website.

AER Allows Resumption of 10 Production Pipelines at Nexen Long Lake; 45 Lines Remain Shut-in (NR2015-15)
News Release – Pipeline Licence Suspension

As an update to its prior suspension order issued on August 28, 2015 which shut in 15 licences held by Nexen Energy ULC ("Nexen"), the AER announced that it had approved the resumption of operations for 10 production pipelines at Nexen's Long Lake facility. 45 pipelines remain shut-in under the suspension order.

The reactivated production pipelines transport miscellaneous gases, including produced steam and vapour, oil emulsion, and natural gas, including produced vapour. The 45 remaining suspended pipelines contain several products, including crude oil, natural gas, salt water, fresh water and emulsion.

Invitation for Feedback: Fluid Tailings Management Draft Directive (Bulletin 2015-27)
Bulletin – Feedback Invitation – Tailings Management

The AER announced it was seeking public feedback on its draft directive regarding fluid tailings management for oil sands mining projects. The release of the draft directive follows from the previous release of the *Lower Athabasca Region: Tailings Management Framework for Mineable Athabasca Oil Sands* ("TMF").

As part of the AER's planned phased approach to the implementation of the TMF, the draft directive establishes application requirements, a review and approval process, and performance reporting requirements for fluid tailings volume profiles. The AER noted that it would implement project-specific thresholds based on information submitted through the application process. Surveillance and enforcement measures associated with the implementation of TMF are expected to be included in the 2016 edition of the draft directive.

Once finalized, the draft directive would rescind the current *Directive 074: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*.

The AER will be accepting feedback on the draft directive until November 17, 2015. A copy of the draft directive can be found here, and stakeholders may provide comments here.

Posting of Participation and Procedural Decisions (Bulletin 2015-28)
Bulletin – Posting of Decisions

The AER announced, effective immediately, that it will post participation decisions and substantive procedural decisions made by hearing panels and other decision-makers on its website. This is a departure from the AER's past practice of providing such decisions only to the parties affected by the decision.

Participation decisions are referred to as decisions made by the AER in respect of whether to hold a hearing on an application, usually in response to a statement of concern or a regulatory appeal. These decisions were formerly known as "standing decisions", and will now be called "participation decisions". These decisions will typically set out the AER's reasons related to whether or not to hold a hearing or regulatory appeal in accordance with the *Responsible Energy Development Act* and its applicable rules and regulations.

Procedural decisions are referred to as decisions made by the AER to determine the course of a proceeding or the filing of information in a proceeding, such as confidentiality orders, deadline extensions, or establishing the scope of issues. Procedural decisions will typically consider and apply the *Alberta Energy Regulator Rules of Practice* as well as principles of fairness and natural justice as applicable to AER proceedings.

The AER noted that although the decisions in respect of participation and procedural matters will be posted to the AER's website, statements of concern and other documents filed will not be posted, but are available through the AER's product catalogue.

Administration of Good Production Practice for Conventional Crude Oil Pools (Bulletin 2015-29)
Bulletin – Good Production Practice

The AER announced changes to the administration of Good Production Practice ("GPP") for wells in a newly defined oil pool. The AER may grant GPP status under section 10.060 of the *Oil and Gas Conservation Rules* ("*OGCR*"), either of its own discretion, or by approving an application under *Directive 065: Resources Applications for Oil and Gas Reservoirs* ("*Directive 065*"). Effective October 1, 2015, the AER will begin using AER form O-38: Application for New Well Base MRL ("O-38") to assign GPP status to a well in a newly defined oil pool where gas is being conserved in accordance with *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*.

However, in the following circumstances, GPP status will not be administered through the O-38 application process and wells will be subject to maximum rate limitation ("MRL") administration:

(a) Wells within a primary depletion area of a pool with enhanced oil recovery approvals; and

(b) Wells in a pool with a gas cap but no approval for concurrent production.

Licensees that wish to operate under GPP in such circumstances must apply in accordance with *Directive 065*.

The AER also announced that it would be reviewing and assessing GPP status for wells, and noted that as part of such review, it may:

(a) Remove GPP and establish rate controls where necessary;

(b) Require licensees to provide data, reports, and interpretations, including performance reports, to characterize the resource and ensure optimum resource recovery under sections 11.005 and 11.006 of the *OGCR*; and

(c) Review pools on maximum rate limitation (MRL) administration and propose GPP if appropriate.

The AER will further be reviewing pools under MRL administration, and beginning October 1, 2015, will grant GPP to pools based on the criteria set out above. GPP status will be posed for qualifying pools in the AER's monthly MRL order.

A full copy of the AER's bulletin can be found here.

ALBERTA UTILITIES COMMISSION

Kingman Rural Electrification Association Ltd. Application for Permission to Cease and Discontinue Operations; FortisAlberta Inc. Sale and Transfer of the Kingman Rural Electrification Association (Decision 20552-D01-2015)

Cease and Discontinue Operation – Sale, Transfer and Operation of Assets

The Kingman Rural Electrification Association Ltd. ("Kingman") applied to the AUC for approval to cease and discontinue the operation of its electric distribution system under section 29 of the *Hydro and Electric Energy Act* ("*HEEA*"). Kingman proposed to sell its assets under section 32 of the *HEEA*.

FortisAlberta Inc. ("Fortis") simultaneously applied to the AUC for approval of the sale, transfer and operation of the Kingman assets under section 32 of the *HEEA*. The AUC considered both applications jointly in this decision.

Four rural electrification associations (the "REAs") intervened in the proceedings on the basis that there were legal and policy oriented issues of interest to them concerning the sale and transfer applications under section 32 of the *HEEA*. The AUC denied the REAs standing on the basis that the applications did not have the potential to directly and adversely affect the REAs.

The AUC held that Kingman had complied with the requirements of the *Rural Utilities Act* for the authorization of a sale of facilities, and that the sale was supported by a majority of members eligible to vote.

In determining the public interest, the AUC relied on Fortis' submission that it would continue to operate and provide service to the members of the services area comprised of the members of Kingman. The AUC also relied upon the evidence demonstrating that the director of rural electrification associations approved the resolutions authorizing the sale and transfer. Accordingly, the AUC determined that the sale of Kingman's assets to Fortis was in the public interest.

The AUC therefore granted Kingman's application to cease to operate under section 29 of the *HEEA*, provided that the facilities are transferred to Fortis. Accordingly, the AUC ordered the transfer of the Kingman service area to Fortis pursuant to section 32 of the *HEEA*, and further directed Kingman to sell (and Fortis to purchase and operate) Kingman's assets in accordance with the asset purchase agreement.

Having approved the application for the sale and transfer of the Kingman assets, the AUC considered the prudence of purchase price to be paid by Fortis for Kingman's assets. Fortis submitted that the purchase price of $5,120,000 was determined on the basis of the replacement costs new less depreciation (RCN-D) formula, which was approved by the AUC in Decision 2013-296. The AUC accepted Fortis' submissions, and therefore determined that the purchase price was prudent and consistent with prior approvals.

With respect to rate impacts, the AUC noted that Fortis was subject to performance-based regulation ("PBR") for a five year term, and would be capable of applying for adjustments over the term. Fortis did not apply, as part of this application, for any adjustments to its rates as a result of the acquisition of Kingman. Therefore, Fortis' rates were unaffected by this decision.

Direct Energy Regulated Services and EPCOR Energy Alberta GP Inc. Review and Variance of Decision 2941-D01-2015: Regulated Rate Tariff and Energy Price Setting Plans – Generic Proceeding: Part B – Final Decision (Decision 20416-D01-2015)

Review and Variance – Denied – Regulated Rate Tariff – Energy Price Setting Plans

Direct Energy Regulated Services Inc. ("DERS") and EPCOR Energy Alberta GP Inc. ("EPCOR") both applied for a review and variance of Decision 2941-D01-2015. In Decision 2941-01-2015, the AUC considered, through a generic proceeding, all of the elements of the energy price setting plans ("EPSP") for all three regulated rate option ("RRO") providers, including the reasonable return component of their respective regulated rate tariffs ("RRT").

Both DERS and EPCOR raised alleged errors of fact, law or jurisdiction in their grounds for review, as well as concerns regarding procedural fairness in Decision 2941-D01-2015.

<u>Procedural Fairness</u>

With respect to procedural fairness grounds, DERS and EPCOR alleged that the hearing panel was in breach of the duty of procedural fairness by failing to provide notice to the parties that it would make findings in respect of whether investors were inherently risk averse or risk neutral, and whether the RRO providers would receive compensation for price variability.

The AUC held that the hearing panel provided adequate notice of the issues related to the risk margin, citing the hearing panel's release of the final issues list for the proceeding, and each of DERS and EPCOR had a reasonable opportunity to file evidence on the appropriate methodology for the risk margin and commodity risk compensation. The AUC also found that EPCOR had specifically discussed commodity risk compensation and risk aversion in its information request responses to the AUC, and found that ECPOR was not denied an opportunity to make submissions on the issues of risk compensation and risk aversion.

The AUC held that neither DERS nor EPCOR established that there was a breach in procedural fairness or in legitimate expectation, and denied the application for review on this ground.

<u>Errors of Fact, Law, or Jurisdiction</u>

Interpretation of Section 6(1)(a) of the Regulated Rate Option Regulation

DERS and EPCOR raised two grounds of review in respect of section 6(1) of the *Regulated Rate Option Regulation*:

(a) The hearing panel erred in finding DERS and EPCOR are only to recover risk-related costs and expenses, instead of just and reasonable compensation for bearing financial risk as well as risk-related costs and expenses; and

(b) The hearing panel erred in failing to provide DERS and EPCOR with an opportunity to earn just and reasonable compensation in relation to the risk margin.

The AUC held that the hearing panel did not commit an error in its interpretation of section 6(1)(a) of the *Regulated Rate Option Regulation*, holding that the hearing panel considered both provisions in its analysis, as well as section 6(1)(b)(ii). The AUC determined that the hearing panel's interpretation or the standard to be applied was reasonable and consistent with a contextual reading of the *Electric Utilities Act*. The AUC also noted that the hearing panel held a generic proceeding for a specific reason, that being to look at different approaches than previously employed by the RRO providers in the past. The AUC noted that it should not be a surprise to any party that the hearing panel later adopted a different approach.

The AUC summarized DERS and EPCOR's contention as being that, in order to comply with the relevant legislation, the hearing panel ought to have quantified each specific element of commodity risk. Instead, the AUC noted the hearing panel's approach as considering all of the elements of commodity risk in approving a two-part compensation formula.

The AUC reiterated that section 103(1) of the *Electric Utilities Act* requires a RRO provider to prepare an RRT for the purpose of recovering the prudent costs of providing electricity to eligible customers. The onus is on the RRO provider to justify the RRT as just and reasonable, and includes the RRO provider's proposed risk margin.

The AUC determined that the methodology for calculating the risk margin was submitted on the record by the UCA, and considered all risk elements (although the selected methodology did not consider each element separately).

In dismissing DERS' and EPCOR's request for a review on this ground, the AUC cited the Alberta Court of Appeal's reasons in *EPCOR v Alberta (Energy and Utilities Board)* stating that the AUC "is free to accept or reject evidence presented by the parties and, as an expert tribunal, it is entitled to use its expertise to arrive at different conclusions than the parties." Therefore, the AUC ruled that it was well within the hearing panel's discretion to accept the UCA's proposed methodology, and to reject those applied for by DERS and EPCOR.

Accordingly, the AUC held that DERS and EPCOR had not shown that an error in fact, law or jurisdiction was obvious on the face of the decision or had been shown to exist on a balance of probabilities.

The AUC further rejected EPCOR's submission that the hearing panel made findings in respect of whether RRO investors were risk averse or risk neutral. The AUC noted the hearing panel's lengthy discussion of financial risk consisting of some 300 paragraphs of discussion and reasons. The AUC found that the hearing panel was not under a duty to alert the parties that it was considering a part of the hearing record. The parties were afforded a reasonable opportunity to file evidence, make argument and reply before the hearing panel on any issue raised in the course of the proceeding. The AUC noted that the hearing panel did not have a responsibility to ensure that the hearing participants each addressed every issue raised in the proceeding.

The AUC agreed with EPCOR and DERS that past decisions generally assumed that public utility companies were risk averse. However, the AUC distinguished EPCOR and DERS from "public utility companies", since they are RRO providers. EPCOR and DERS are not considered monopolies, but are regulated under the *Regulated Rate Option Regulation* as part of a competitive market. The AUC also noted that neither EPCOR nor DERS' RRO service are capital intensive like transmission and distribution utilities, finding therefore that the hearing panel did not commit an error in finding that RRO investors are risk neutral, not risk averse.

Deferral accounts or True-Ups

DERS submitted that the hearing panel erred in approving an RRT and EPSP methodology that uses, provides for, or contemplates the use of deferral accounts, true-ups, rate riders or other similar adjustment mechanisms.

The AUC determined that the hearing panel did not err in approving its rolling 12-month price methodology, as the hearing panel noted specifically that although historical data is used, it is applied prospectively. No settlement or reconciliation would occur at the end of the period. The AUC held that the hearing panel appropriately considered whether the approved methodology resulted in a deferral account based on the evidence before it. DERS had not raised a reasonable possibility that the alleged error of fact or law could reasonably lead the Commission to materially vary or rescind the decision.

Interpretation of Section 6(1)(d) of the Regulated Rate Option Regulation

DERS and EPCOR submitted that the hearing panel erred in approving a commodity risk compensation that would impede the development of an efficient market based on fair and open competition, and in approving an RRT that is unduly preferential, arbitrary and unjustly discriminatory.

DERS argued that the hearing panel fundamentally misconstrued the purpose of the *Electric Utilities Act* in its interpretation of economic efficiency, and failed to properly apply principles of statutory interpretation, by referring to extrinsic aids instead of the words used in the *Electric Utilities Act* and the *Regulated Rate Option Regulation*.

EPCOR made similar submissions, arguing that the hearing panel approved a commodity risk compensation that fails to provide just and reasonable financial compensation as required under the *Regulated Rate Option Regulation*.

The AUC characterized the complaints of DERS and EPCOR as being that the hearing panel did not give them enough money. The AUC determined that it had already considered these arguments in respect of commodity risk compensation, and concluded that the hearing panel did not err in its approach. The AUC further dismissed the arguments in respect of errors in statutory interpretation. The AUC noted that the hearing panel stated that economic efficiency was a key component of a competitive market for electricity in Alberta. In support of its statements, the hearing panel cited past AUC decisions, including Decision 2011-226, which refers to Hansard materials. The AUC found that the hearing panel did not undertake an exercise in statutory interpretation, but rather a review of its own decisions, which it applied in its reasons. The AUC therefore dismissed this ground of review, finding that DERS and EPCOR had not raised a reasonable possibility that the hearing panel committed an error of fact, law or jurisdiction that could reasonably lead the AUC to materially vary or rescind its findings in Decision 2941-D01-2015.

<u>Conclusion</u>

The review panel, in accordance with the findings above, found that DERS and EPCOR had not raised a reasonable possibility that the hearing panel committed an error of fact, law or jurisdiction that could reasonably lead the AUC to materially vary or rescind its findings in Decision 2941-D01-2015. The AUC dismissed the applications for review.

Direct Energy Marketing Limited Application for Approval of an Exemption Under Section 41(1)(a) of the Gas Utilities Code of Conduct Regulation, AR 183/2003 (Decision 20534-D01-2015)

Gas Utilities Code of Conduct Regulation – Exemption from Audit Requirements

Direct Energy Marketing Limited ("DEML") applied on its behalf and on behalf of Direct Energy Regulated Services ("DERS") and Direct Energy Partnership ("DEP") for an exemption from the compliance audit requirements in sections 37 to 40 of the *Gas Utilities Act Code of Conduct Regulation* for 2014.

In support of its application, DEML submitted that the number of contraventions decreased from 12 in 2013, to 9 in 2014 for DEP. DEML noted that the percentage of employees not completing compliance training on time was reduced from 0.80 percent of 0.34 percent over the same period. The number of contraventions for not obtaining compliance approval prior to using marketing materials was also reduced from three incidents in 2013 to one incident in 2014. DEML also noted that there was zero code of conduct contraventions for DERS in 2014. Accordingly, DEML submitted that an exemption would not be detrimental to the public interest, given that it continues to file compliance plan reports on a quarterly basis, and provides an annual report in respect of the same.

The AUC held that it was satisfied with DEP's efforts to reduce noncompliance events over the 2013 to 2014 period, specifically as relates to compliance training and prior approval for the use of marketing materials. The AUC also noted that there were no contraventions for DERS reported in 2014. Based on DEML's submissions, the AUC determined that granting an exemption would not significantly affect the obligations of DERS and DEP to continue to comply with their respective obligations under their compliance plans. The AUC granted DEML's request for an exemption from the audit requirements of section 37 to 40 of the *Gas Utilities Act Code of Conduct Regulation* for 2014.

Office of the Utilities Consumer Advocate Review and Variance of Decision 2941-D01-2015: Regulated Rate Tariff and Energy Price Setting Plans – Generic Proceeding: Part B – Final Decision (Decision 20419-D01-2015)
Review and Variance – Denied – Regulated Rate Tariff – Energy Price Setting Plans

Pursuant to sections 6(2)(a)(i) and (ii) of AUC Rule 016: *Review and Variance of Commission Decisions*, the Office of the Utilities Consumer Advocate ("UCA") sought a review and variance of AUC Decision 2941-D01-2015.

Decision 2941-D01-2015 concerned Regulated Rate Tariffs ("RRT") and Energy Price Setting Plans ("EPSP") for Direct Energy Regulated Services ("Direct Energy"), ENMAX Energy Corporation ("ENMAX") and EPCOR Energy Alberta GP Inc. ("EPCOR"), the three regulated rate option providers in the province (collectively the "RROs").

The UCA sought the review and variance of Decision 2941-D01-2015 on the grounds that ongoing third party monitoring of the RRO procurement activities under each of their EPSPs was not required. The UCA raised the following grounds in support of its application:

(a) The hearing panel erred in finding the current role of the Independent Advisor ("IA") is limited to providing technical advice ("Ground A");

(b) RROs are not incented to provide the lowest regulated rate option consistent with legislative requirements ("Ground B");

(c) The reporting of information through transparent monthly filings is not a sufficient substitute for third party monitoring and oversight ("Ground C");

(d) The oversight by the Market Surveillance Administrator ("MSA") is not an adequate solution to obtain the lowest regulated rate ("Ground D"); and

(e) The MSA's State of the Market Report (the "MSA Report") provides new facts, which were not previously placed in evidence, which could lead the AUC to materially vary or rescind the decision ("Ground E").

With respect to Ground A, the UCA submitted that the AUC's characterization of the involvement of an independent market expert ("IME") from the IA as "limited to providing technical advice" was an error of fact. The UCA submitted that the IA exercises a considerably greater authority and discretion with respect to EPSPs in applying its expertise in monitoring the electricity market to set target prices.

The RROs submitted that the UCA's submissions on the expertise of the IA supported the AUC's conclusion that the IA's role was primarily technical in function. The RROs submitted that the AUC appropriately considered the role of the IA under the EPSPs, and that the UCA simply took a statement out of context to characterize it as an error of fact.

The AUC agreed with the RROs, finding that the reference to the IA's role was ancillary to the finding that an IME was not required, and that the statement should not have been interpreted in isolation from the balance of the AUC's findings in Decision 2941-D01-2015. The AUC dismissed Ground A of the UCA's review and variance application.

With respect to Ground B, the UCA submitted that the absence of an externally imposed mandate to minimize rates would result in the RROs not being incented to achieve the lowest base energy charge ("BEC") for its ratepayers. The presence of competitive affiliates in conjunction with higher regulated rate option rates effectively made the regulated rate option a "price ceiling" or "price to beat", which in turn raises rates for all customers compared with a wholly competitive market. Competitive affiliates of the RROs provided an incentive to encourage RROs to have higher rates incenting customers to enroll with the RROs' competitive affiliate, and thereby earn a larger return or achieve other benefits. The AUC's failure to provide an incentive for lower regulated rate option rates resulted in a mechanistic pricing mechanism, which may be susceptible to being deduced and manipulated by other market participants.

The AUC noted that the UCA, in its submissions acknowledged that RROs are not required to provide the lowest regulated rate. The UCA's concern was rather with the lack of motivation on the part of RROs to provide the lowest regulated rate. The AUC held that the AUC properly interpreted the requirements of the *Regulated Rate Option Regulation*, which did not require EPSPs to seek the lowest possible price, noting specifically that the AUC considered that the mandatory 120-day price setting window may cause upward pressure on rates. The AUC noted that the original hearing panel appropriately considered the evidence before it, and sufficiently tested the EPSPs, as well as rates and other incentives. The AUC held that its role in a review and variance was not to re-weigh the evidence previously decided. The UCA's submissions were essentially a re-statement of its submissions in the original proceeding.

With respect to Ground C, the UCA submitted that oversight through monthly reporting was not an appropriate substitute for real-time oversight and monitoring by an IME. The UCA submitted that monthly reports would provide little auditable information, showing only general bid and offer ranges for transactions made at a particular time of day. The UCA also submitted that the *ex-post* facto nature of monthly reporting effectively shifted the onus on to customers to object to the calculation of energy charges through trades for any given month.

The AUC held that the hearing panel did not make any finding that the monthly findings were a monitoring mechanism, but simply a review mechanism. Monitoring occurred during the activity in question, while reviewing occurred after the fact. The hearing panel only made a finding with respect to the latter. In any event, the UCA's submissions on Ground C did not demonstrate a reasonable possibility that the information from a monitoring arrangement would be superior to a monthly report. Monthly reports would allow parties to check the accuracy of calculations, and to identify any potential trends. For these reasons, the AUC also dismissed Ground C. Ground C did not raise a reasonable possibility that the hearing panel committed an error of fact, law or jurisdiction.

With respect to <u>Ground D</u>, the UCA submitted that oversight by the MSA was not an adequate solution to obtain the lowest regulated rates. The AUC accordingly erred by relying on the MSA's investigative and surveillance function as justification to support its findings. The UCA submitted that while the MSA encourages RROs to comply with market based prices under the *Regulated Rate Option Regulation*, a market-based price was not the same as the lowest price. The UCA also submitted that DERS and ENMAX conducted large volumes of their respective trades through over-the-counter transactions, and that the MSA's ability to review such transactions were only on an *ex post facto* basis. This arrangement was not a sufficient substitute for third-party monitoring of the RROs procurement practices.

The AUC noted its previous determination that the *Regulated Rate Option Regulation* did not require RRO providers to procure at the lowest possible rate. Therefore, the hearing panel had not committed an error in finding that the MSA provides appropriate oversight of the RROs' procurement activities. The AUC dismissed Ground D.

With respect to <u>Ground E</u>, The UCA submitted that given the timing of the MSA Report, parties did not have adequate time to consider the effects of the MSA report on the original decision. The UCA further submitted that the MSA Report provided new facts, which were not previously placed in evidence, which could lead the AUC to materially varying or rescinding its decision.

The AUC found that, although the MSA Report was released near the close of the proceeding, the information was public prior to the end of the proceeding. The AUC also relied on the fact that the MSA Report was a quarterly report, and it was reasonable for all parties to have expected the report to be issued at the time that it was.

The AUC further found that the MSA Report did not contain any information that would lead it to materially varying or rescinding the decision. Therefore the AUC dismissed Ground E.

Alberta Electric System Operator Application regarding Critical Infrastructure Protection Alberta Reliability Standards (Decision 3441-D01-2015)
Reliability Standards

The Alberta Electric System Operator ("AESO") applied, pursuant to section 19 of the *Transmission Regulation*, for approval of 11 recommended new Critical Infrastructure Protection ("CIP") Alberta reliability standards related to cyber security (the "CIP Standards"). The application was accompanied by two additional applications by the AESO:

(a) One application for 22 new reliability standard definitions; and

(b) One application pertaining to whether the costs to be incurred by a particular generating unit owner to comply with the new CIP Standards are the responsibility of the generating unit owner or the AESO.

The 22 new reliability standard definitions were considered in Decision 3442-D01-2015, discussed below. The latter application regarding costs would be considered at a later date in Proceeding 3443.

The AESO submitted that the CIP Standards were adopted from the North American Electric Reliability Corporation ("NERC") Version 5 CIP reliability standards, with modifications made by the AESO to ensure that the CIP Standards were applicable to Alberta. The AESO submitted that the proposed CIP Standards were in the public interest, as Alberta did not have any standards in place for protecting critical infrastructure from cyber attacks. The AESO proposed a two-year transition period to implement the standards as reasonable, appropriate and in the public interest.

TransCanada Energy Ltd. ("TCE") objected to the CIP Standards on the basis that they were technically deficient in satisfying the requirements of Section 19(6) of the *Transmission Regulation*. With respect to public interest matters, TCE objected to the two-year effective date in that the AESO provided no factual basis for a two-year effective date. The two-year period was inappropriate in the circumstances, since CIP Standards are new to Alberta, whereas other jurisdictions had earlier versions of CIP Standards in place, and used three-year implementation periods for new standards.

TCE further submitted that the CIP standards were inconsistent with section 21(3) of the *Transmission Regulation*, since the two-year implementation period did not reflect the circumstances of adopting the CIP Standards as compared to other jurisdictions. Section 21(3) requires the AESO to consider whether the proposed CIP Standards are capable of applying in Alberta.

The AESO stated that delaying the implementation of the CIP standards would be contrary to the public interest given the lack of protection to Alberta's bulk electric system ("BES") from cyber attacks, even if TCE could demonstrate a cost savings for delaying implementation. Incremental costs or lost opportunity costs may be avoided if TCE applied for a variance in accordance with the CIP-SUPP reliability standard.

The AUC acknowledged that the submissions of TCE in respect of compliance costs for reliability standards, noting that as a PPA buyer, it may be adversely impacted by the implementation of the CIP Standards. The AUC further noted that such costs and increased outages may affect the market as a whole, but ultimately dismissed these submissions as speculative in nature.

The AUC determined that the AESO was in the best position to determine the risks facing the Alberta electrical system, and agreed that the proposed two-year implementation was reasonable and necessary. The AUC held that TCE did not provide cogent evidence of how the CIP Standards were technically deficient or not in the public interest in this regard, thereby dismissing the objection.

The AUC held that section 19 of the *Transmission Regulation* did not require the AESO to carry the onus of proving the public interest of the two-year effective date. Section 19(6) creates a statutory presumption that the AESO's recommendation to implement a reliability standard was in the public interest, without requiring any evidence from the AESO. The AESO's modifications in and of themselves were evidence that the AESO gave substantial consideration to the capability and applicability of the CIP Standards in Alberta. The AUC accordingly found no contravention of the CIP Standards with the *Transmission Regulation*.

In accordance with the reasons set out in the decision, the AUC ruled that:

(a) No interested party satisfied the AUC that the AESO's recommendation was technically deficient or not in the public interest; and

(b) No contravention of Section 21(3)(a) of the *Transmission Regulation* was proven that might render the AESO's recommendation to approve the CIP Standards not in the public interest.

The AUC approved the CIP Standards to become effective on the dates proposed by the AESO.

Alberta Electric System Operator Application regarding Alberta reliability standards definitions (Decision 3442-D01-2015)
Reliability Standards

As noted in the summary of Decision 3441-D01-2015 above, the Alberta Electric System Operator ("AESO") applied, pursuant to section 19 of the *Transmission Regulation*, for approval of 22 recommended new reliability standard definitions to be added to the ISO Consolidated Authoritative Document Glossary.

These terms were noted by the AESO as being related to the AESO's applied for approval of 11 Critical Infrastructure Protection Alberta reliability standards ("CIP Standards").

The AUC determined that, although Capital Power Corporation, TransAlta Corporation, TransCanada Energy Ltd., and EPCOR Distribution & Transmission Inc. filed objections to the proposed new definitions, the evidence did not raise any specific concerns with the proposed reliability standard definitions. Therefore, as none of the participants demonstrated that the AESO's application was technically deficient or not in the public interest, as required under section 19(6) of the *Transmission Regulation*, the AUC approved the new reliability standard definitions, effective October 1, 2017.

ATCO Electric Ltd. Disposition of Land and Buildings in Grande Prairie and Lloydminster (Decision 20329-D01-2015)
Disposition of Property

ATCO Electric Ltd. ("ATCO") applied to the AUC requesting approval to dispose of three properties:

(a) 9717 – 97 Avenue, Grande Prairie, Alberta (the "GP Administration Office");

(b) 9139 Park Road, Grande Prairie ("GP Service Centre"); and

(c) 6208 – 48 Street, Lloydminster ("Lloydminster Service Centre").

(collectively the "Properties").

ATCO requested the disposal of the Properties pursuant to section 101(2)(d) of the *Public Utilities Act*.

ATCO submitted that the GP Administration Office and GP Service Centre were shared by its transmission and distribution operations, while the Lloydminster Service Centre was solely used for distribution operations. The GP Administration Office was originally acquired by ATCO in 1983, consisting of land and one building with offices and garage bays. The GP Service Centre was originally acquired by ATCO in 1972, consisting of land and three buildings. The Lloydminster Service Centre was acquired by ATCO in 1977, consisting of land and one building with offices and garage bays.

ATCO confirmed that it removed the net book value of the Properties from rate base on December 31, 2013 when the Properties were no longer used for utility service. ATCO submitted the following net book values in support of its application:

	Original Land Cost	Original Building Cost	Accumulated Depreciation	Net Book Value removed from Rate Base
GP Administration Office	$30,660	$2,182,562	$946,690	$1,266,532
GP Service Centre	$24,819	$2,451,151	$950,323	$1,525,648
Lloydminster Service Centre	$107,309	$2,489,748	$891,440	$1,705,616
Total	**$162,788**	**$7,123,461**	**$2,788,453**	**$4,497,796**

ATCO submitted that recent market appraisals estimated the value of the Properties as follows:

(a) GP Administration Office - $3.9 million;

(b) GP Service Centre - $3.4 million; and

(c) Lloydminster Service Centre - $2.1 million.

ATCO applied for a monetary threshold of $1.8 million to be used in determining if a particular asset is outside the ordinary course of business. Since each of the assets in question met the proposed threshold, ATCO sought to dispose of the Properties in one application for efficiency purposes.

ATCO sought to transfer each of the Properties through a series of transactions to its non-regulated affiliate, ATCO Real Estate Holdings Ltd., in exchange for cash equal to the net book value of the Properties and shares in ATCO Real Estate Holdings Ltd. for the balance of the fair market value of the Properties. ATCO described the remainder of the transactions as follows:

(a) ATCO would then redeem the shares for a promissory note from ATCO Real Estate Holdings Ltd;

(b) ATCO would in turn distribute the promissory note to its corporate parent, CU Inc., as a dividend;

(c) CU Inc. would in turn distribute the promissory note on to Canadian Utilities Limited as a dividend;

(d) Canadian Utilities Limited would contribute the promissory note to ATCO Real Estate Holdings Ltd. as a subscription for additional common shares in ATCO Real Estate Holdings Ltd.; and

(e) ATCO Real Estate Holdings Ltd. would cancel the promissory note.

ATCO submitted that the sale and transfers of the Properties would not adversely affect ratepayers.

The AUC had concerns with ATCO's timing of relocation to its replacement facilities for each of the Properties, as it determined that the replacement facilities were ready for occupancy on December 2012 for the GP Administration Office and GP Service Centre, and February 2012 for the Lloydminster Service Centre. The AUC also noted that the new facilities were added to rate base on the same month they were ready for occupancy, but that ATCO did not remove the Properties from rate base until December 31, 2013.

ATCO submitted that the Properties needed to remain in service during a transition period, pointing to difficulties with the transfer of equipment, staff and materials during the spring thaw. The Utilities Consumer Advocate ("UCA"), while supporting the disposition, submitted that a transition period of up to 22 months to transfer three offices was unreasonable, and was not justified by the occurrence of a spring thaw. The UCA recommended that the AUC disallow the return, depreciation, taxes and maintenance costs incurred by ratepayers for the Properties for the period in question.

Ultimately, the AUC accepted the timing of the removal of the Properties for rate base in the absence of evidence of what a reasonable time to transfer equipment and material from one service centre to another would have been in the circumstances. The AUC rejected the UCA's request to disallow ATCO's return, depreciation, taxes and maintenance costs incurred by ratepayers for the Properties between February 2012 and December 31, 2013. Accordingly, as ATCO had removed the Properties from rate base at the time that they ceased to be used for utility service, the AUC considered it unnecessary to consider whether the disposition of the Properties was an ordinary retirement or an extraordinary retirement.

With respect to whether the disposition of the Properties would be outside the normal course of business, ATCO submitted:

(a) That the proceeds of disposition of each of the Properties would be above its proposed threshold;

(b) That such dispositions were infrequent, pointing to Decision 2012-339 as ATCO's last such disposition over the past 10 years; and

(c) As a percentage of rate base, the value of the Properties was similar to that established for ATCO Gas at $1.5 million, based on a $2.207 billion rate base.

With respect to rate impacts, ATCO submitted that its total going-in rates for the Properties in its 2012 performance-based regulation ("PBR") application were $0.6 million. ATCO submitted that the AUC previously approved its capital tracker program for Buildings, Structures and Leasehold Improvements in Decision 3218-D01-2015 as a "K factor" adjustment.

The AUC approved of this method of accounting for the disposition of the Properties under PBR as reasonable, and considered that the removal of the Properties in 2013 would need to be accounted for in ATCO's next cost-of-service application for rate-setting purposes.

The AUC held that it was not prepared to apply a generic materiality test, as it preferred to assess the dispositions given the facts of each transaction. However, the proposed transactions, and the net book value of the Properties at the time of disposition suggests that the dispositions would be outside the ordinary course of ATCO's business. The AUC noted that it may consider the establishment of generic thresholds as part of a future generic proceeding to fully test ATCO's assumptions.

The AUC accepted that such dispositions by ATCO were infrequent, and supported its finding that the disposition of the Properties would be outside the ordinary course of business.

The AUC held that the disposition of the Properties would not harm ratepayers. The AUC relied on submissions from ATCO that customers would not be liable for any of the costs of the dispositions of the Properties, and that the Properties had already been removed from rate base.

The AUC approved ATCO's application to dispose of the Properties.

ENMAX Power Corporation Decision on Request for Review of Decision 3368-D01-2015 regarding 138-2.82L and 138-2.83L Transmission Realignment (Decision 20612-D01-2015)

Review and Variance – Denied – Transmission Line Realignment

Remington Development Corporation ("Remington") filed an application with the AUC for a review of Decision 3368-D01-2015, in which the AUC denied an application filed by ENMAX Power Corporation ("ENMAX") for the realignment of two transmission lines:

(a) 138-2.82L, which runs between ENMAX's substation No. 2 and No. 5 in Calgary; and

(b) 138-2.83L, which runs between ENMAX's substation No. 5 and No. 13 in Calgary.

Both lines are located on right-of-way lands owned by Remington. Remington terminated the right-of-way agreement, which was the subject of protracted litigation. A decision from the Court of Queen's Bench directed ENMAX to apply to the AUC to remove the lines.

ENMAX's application to the AUC to remove the lines, which resulted in Decision 3368-D01-2015, considered six options for relocating the lines. Options 1 through 4 proposed to acquire land or a right-of-way from Remington for an overhead or underground configuration. Option 5 would relocate portions of the lines to lands owned by Alberta Infrastructure. Option 6, which was the proposed route, would relocate the lines to an underground City of Calgary alignment. ENMAX rejected alternatives 1 through 4 on the basis that Remington indicated it wanted all transmission infrastructure removed from its lands, and option 5 was also rejected as Alberta Infrastructure refused to grant a right-of-way due to future development plans.

Remington did not participate in the proceeding which resulted in Decision 3368-D01-2015, and the AUC noted that Remington did not seek leave of the AUC to file its review application, but that it was a registered party to the original decision. The AUC also noted that despite Remington's submission that its counsel attended the original hearing, the AUC determined that its counsel did not register for or appear on the record of the oral hearing. However, given that the lines are located on Remington's lands, the AUC exercised its discretion to grant Remington leave to file its review application.

Remington submitted that the original AUC panel committed errors of fact, law and jurisdiction, in expropriating its lands, and by condoning trespass on Remington's lands by allowing ENMAX to continue having the lines located on its lands.

The AUC determined that there was no expropriation resulting from Decision 3368-D01-2015. The AUC found that the transcript of the proceeding supports the view that the lines may continue to occupy the right-of-way either by agreement or by way of right-of-entry order from the Surface Rights Board. The AUC held that the original panel addressed the manner in which the lines could remain on the lands in accordance with the *Hydro and Electric Energy Act*.

The AUC also held that the review application was not a second opportunity for Remington to raise issues regarding the acquisition of a right-of-way that it chose not to raise in the original proceeding. The AUC pointed to the lack of information on the record concerning Remington's development plans, and the impact of the lines remaining in place or being relocated. The AUC noted that ENMAX's primary justification for removing the lines was Remington's refusal to continue hosting the lines on their lands. Therefore the AUC determined that Remington had not raised a reasonable possibility that the original panel committed an error of fact, law or jurisdiction that could lead the AUC to vary or rescind Decision 3368-D01-2015.

The AUC dismissed Remington's application for review.

Market Surveillance Administrator allegations against TransAlta Corporation et al. Phase 2 Preliminary matters: Standing and Restitution (Decision 3110-D02-2015)
Standing – Restitution

This decision considered preliminary matters of Phase 2 in the Market Surveillance Administrator's ("MSA") allegations against TransAlta Corporation, TransAlta Energy Marketing Corp. and TransAlta Generation Partnership (collectively "TransAlta"). In Phase 1 of the proceedings, the AUC determined that TransAlta had contravened Section 6 of the *Electric Utilities Act* (the "*EUA*") and sections 2(h) and (j), and section 4 of the *Fair Efficient and Open Competition Regulation* (the "*FEOC Reg*") in late 2010 and early 2011. The main portion of Phase 2 will consider what sanctions, if any, to impose against TransAlta pursuant to section 56 and 63 of the *Alberta Utilities Commission Act* ("*AUCA*").

The AUC considered two main issues in this decision:

(a) The AUC's jurisdiction to order restitution; and

(b) Matters related to standing for the Utilities Consumer Advocate ("UCA") and Direct Energy Regulated Services ("DERS").

Jurisdiction to Order Restitution

The AUC determined that its jurisdiction to order restitution was a question of statutory interpretation under sections 56 and 63 of the *AUCA*. The AUC determined that sections 56 and 63 of the *AUCA* do not expressly provide restitution as an available remedy for contraventions of the AUC's governing legislation. The AUC also noted that several other regulatory schemes in Alberta specifically identify restitution as an available remedy, citing the *Securities Act*, *Conflicts of Interest Act*, the *Gas Distribution Act*, the *Public Service Act*, and the *Loan and Trust Corporations Act*. The AUC found that, while not determinative of the issue, the absence of an express power to order restitution was a strong indication that the Legislature did not intend to grant the AUC powers to order restitution.

The AUC held that, although section 8, 11 and 23 of the *AUCA* provided broad powers to the AUC, such authority did not provide unlimited discretion. The AUC determined that such broadly drawn powers must necessarily be limited to only what is rationally connected to the purpose of the regulatory framework. As such, the AUC found that the purpose behind such grants of authority to order sanctions was to achieve general or specific deterrence, to encourage compliance, and to protect the public. Such deterrence, and protection could be effectively achieved through the imposition of a one-time amount and the disgorgement of the economic benefits associated with TransAlta's conduct. Therefore, the AUC held that it could not reasonably rely on its general powers to infer any authority to order restitution either in addition to, or instead of, sanctions it is specifically authorized to impose.

Standing

The UCA and DERS requested standing before the AUC in Phase 2 of the proceeding.

The UCA submitted that it has a legislated mandate to represent the interests of Alberta consumers of electricity and natural gas before the AUC. Given the AUC's findings on increased pool prices as a result of TransAlta's conduct, the UCA argued that its constituents were clearly directly and adversely affected by TransAlta's conduct.

DERS submitted that it was a provider of the regulated rate option in ATCO Electric Ltd.'s service territory, and submitted that it suffered significant and direct financial harm as a result of TransAlta's conduct, in the order of approximately $350,000.

The AUC applied the two part test adopted in *Cheyne v Alberta (Utilities Commission)*, asking first whether the claim, right or interest was known to the law, and second, whether the AUC has information which shows that the person's rights may be directly and adversely affected.

The AUC also considered its general approach to assessing standing in enforcement proceedings, as set out in Bulletin 2010-17. Bulletin 2010-17 sets out that the nature of enforcement proceedings are such that the only parties directly impacted by the outcome of the AUC's findings are the MSA, who brought the allegations, and the alleged contravener.

The AUC considered prior enforcement proceedings, noting that while the UCA was found not to have met the standing test in earlier proceedings, the AUC still granted standing to the UCA on a discretionary basis. Standing was granted due to the UCA's special concern or insight being different that that provided by the MSA. The AUC noted that in such circumstances, it did not allow interveners to sit witnesses or cross-examine the MSA or the alleged contravener.

With respect to the specific claims of the UCA in this proceeding, the AUC held that the UCA is empowered to represent a subset of rate-payers before the AUC, but that its mandate does not include any reference to enforcement or compliance matters. Despite this finding, the AUC held that it was prepared to accept that the UCA has legally recognized interests arising from its statutory mandate, in satisfaction of the first branch of the standing test.

However, the AUC determined that the UCA failed to establish that it may be directly and adversely affected by the AUC's decision. Any sanctions levied by the AUC, in Phase 2, would be against TransAlta, and TransAlta alone. On this basis, the AUC held that the UCA did not have standing to participate in the proceeding.

The AUC determined that DERS' submission was speculative, and in any case, failed to adequately address the two branches of the standing test. The AUC reiterated its finding that any harm suffered by the person requesting standing was a separate and distinct consideration from harm that may be suffered in Phase 2 of this proceeding. On this basis, the AUC held that DERS did not have standing to participate in the proceeding.

The AUC concluded its decision with an updated process schedule for the proceeding which can be found on page 18 of this decision.

TransAlta Corporation 2013-2014 General Tariff Application Refiling in Respect of Decision 3466-D01-2015 (Decision 20524-D01-2015)

General Tariff Application - Refiling

TransAlta Corporation, as Manager of the TransAlta Generation Partnership ("TransAlta") applied for approval of its 2013-2014 general tariff application ("GTA") refiling pursuant to the directions issued in Decision 3466-D01-2015. TransAlta's GTA refiling included three parts:

(a) Section A – Tariff adjustments;

(b) Section B – Responses to the Commission's directions; and

(c) Section C – Revised 2013-2014 schedules.

With respect to <u>direction 1</u>, the AUC directed TransAlta to revise its calculations of the legal expenses associated with the Blood Reserve fire, as it had been double counted. TransAlta submitted that it removed the portion of those amounts associated with the Blood Reserve fire from its account for outside services employed (i.e. USA 923).

The AUC held that it was satisfied that TransAlta had reduced the amounts as directed. TransAlta's amounts for outside services employed were therefore approved as filed.

TransAlta submitted that it would address <u>directions 2 and 3</u> from Decision 3466-D01-2015 in its next GTA.

With respect to <u>direction 4</u>, the AUC directed TransAlta to make any further changes to working capital amounts as a result of the remaining directions in Decision 3466-D01-2015. TransAlta submitted that it had revised its 2013 and 2014 working capital amounts. TransAlta noted that it identified an error in its schedule for calculating amounts on its initial filing, but submitted that it had no impact on the return on rate base as requested in the GTA refiling, as the impact of the error was beyond the level of precision shown in the schedules.

The AUC held that it was satisfied that the updated calculation of necessary working capital reflects the adjustments necessitated by direction 4, and approved TransAlta's working capital amounts as filed.

In <u>direction 5</u>, the AUC directed TransAlta to make any further changes to depreciation amounts as a result of the remaining directions in Decision 3466-D01-2015. TransAlta submitted that none of the AUC's directions in Decision 3466-D01-2015 affected its calculation of depreciation amounts.

The AUC approved TransAlta's depreciation amounts as filed.

In direction 6, the AUC directed TransAlta to update its return on equity amounts to reflect the AUC's findings in Decision 2191-D01-2015 establishing a generic return on equity percentage of 8.3 percent for 2013, 2014 and 2015. TransAlta submitted that it had updated the return on equity calculations in schedules 3-1, 9-1, and 28-1 of the GTA refiling.

The AUC held that the updated calculations in TransAlta's GTA refiling reflect the AUC's findings in Decision 2191-D01-2015 and therefore approved TransAlta's return on equity as filed.

In direction 7, the AUC directed TransAlta to make any further changes to income tax amounts as a result of the remaining directions in Decision 3466-D01-2015. TransAlta submitted that it had revised its income tax expenses to reflect the AUC's filing. TransAlta further noted that due to the ongoing one-year deferral effect of its annual income tax expense, the impacts of the revisions for 2013 are deferred to 2014, and the 2014 revisions will be reflected in TransAlta's 2015 test year.

The AUC approved TransAlta's refilled income tax expenses for 2013 and 2014 as filed.

In direction 8, the AUC directed TransAlta to discuss whether TransAlta would be able to develop a reasonable test period forecast by removing the requirement for TransAlta to wait until AltaLink has filed its GTA before filing its tariff application. TransAlta submitted that while it currently works with AltaLink to develop a one-year forecast for capital maintenance and capital additions, it would require additional resources to develop a similar two-year forecast. TransAlta submitted that the required investment to develop and defend such an extended forecast period would not provide much, if any, reduction in the regulatory lag associated with approval of TransAlta's GTAs.

The AUC held that, given the small size of TransAlta's revenue requirement, the regulatory lag associated with its GTAs are not harmful to consumers. The AUC held that any associated reduction in regulatory lag would not be sufficient to justify the costs, and therefore the AUC did not order any change to TransAlta's filing requirements.

In Decision 3466-D01-2015, the AUC directed TransAlta to reconcile its 2013 and 2014 revenue requirements against the interim tariff rates authorized in Decision 2014-053. TransAlta calculated a revenue shortfall of $506,377 for both 2013 and 2014, and requested approval for a one-time lump sum payment from the Alberta Electric System Operator. TransAlta calculated its net shortfall as follows:

(a) 2013 refund amount of $27,978;

(b) 2014 shortfall of $478,410; and

(c) Deferral account reconciliations for 2013 and 2014 of $55,945.

The AUC held that the deferral account reconciliations were already approved in Decision 3466-D01-2015. The AUC agreed with TransAlta's calculations for balances in 2013 and 2014 by comparing the approved interim rates with TransAlta's requested final revenue requirement in its GTA refiling. Accordingly, the AUC approved the final tariff reconciliation in the amount of $506,377.

As a result the reconciliation and approval of the revenue requirements on a final basis for 2013 and 2014, the AUC ordered TransAlta to invoice the Alberta Electric System Operator for a one-time lump sum payment of $506,377.

The ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) Compliance Filing to Decision 2954-D01-2015 (Decision 20273-D01-2015)
Compliance Filing – Pension Costs

ATCO Electric Ltd., ATCO Gas and ATCO Pipelines, both divisions of ATCO Gas and Pipelines Ltd. (collectively the "ATCO Utilities") filed a compliance filing to Decision 2954-D01-2015 in respect of the pension costs to be recovered for the 2013 revenue requirement for the transmission portion of the ATCO Utilities. The distribution functions of the ATCO Utilities were noted by the AUC as subject to performance-based regulation ("PBR"), and therefore, the impact of this decision would be subject to the PBR formula, as well as any application for adjustments thereto.

The ATCO Utilities originally requested 2013 pension costs of $7.1 million for ATCO Electric's transmission function, and $5.4 million for ATCO Pipelines to be approved. This request was based on a 2012 pension valuation report which identified a deficiency funding requirement of $248.8 million over the next 25 year period. The ATCO Utilities requested recovery of pension costs using a cost-of-living adjustment ("COLA") based on 100 percent of the consumer price index ("CPI"), up to a maximum increase of three percent per year.

In Decision 2954-D01-2015, the AUC held that there was no material change in circumstances or changes to the provisions of the ATCO Utilities pension plan that would persuade the AUC to find that the requested increase was reasonable. However, in light of the unfunded liability of the pension plan, the AUC found that an application of the COLA at 50 percent of CPI up to three percent was reasonable in setting just and reasonable rates, considering the interest of consumers and the ATCO Utilities.

In this decision, ATCO Utilities submitted that they removed the 100 percent COLA, and adjusted their pension costs based on a 50 percent COLA, and filed the following:

(a) A reconciliation of pension cost placeholders with the amounts set out in Decision 2014-348 and Decision 2013-430;

(b) A summary of 2013 pension costs showing operations and maintenance amounts and capital amounts resulting from the 50 percent COLA; and

(c) A table providing an update of the pension cost placeholders for 2013 and 2014.

ATCO Utilities also provided submissions with respect to its compliance with the six AUC directions from Decision 2954-D01-2015.

In Decision 2954-D01-2015, direction 1 and 2 directed the ATCO Utilities to reduce the 2013 pension expense by removing the 100 percent COLA and substitute a 50 percent COLA in its place, reflecting a reduction to the 2013 defined benefit plan costs of $120,300 and $104,300 to each of the regulated transmission functions.

Directions 3 and 4 of Decision 2954-D01-2015 directed ATCO Utilities to complete a table identifying the impact of the AUC's direction and identify the breakdown between current service costs and special payment costs, broken down into operating and maintenance portions, and capital amounts. The AUC directed that the table should reconcile these amounts with the findings in Decision 2954-D01-2015, Decision 2014-348 and Decision 2013-430.

In direction 5, the AUC directed ATCO Utilities to specify the impact of the application of the 50 percent COLA to its revenue requirements, and to adjust any relevant placeholders in their next general tariff application.

In direction 6, the AUC directed ATCO Utilities to submit its compliance filing prior to March 16, 2015. As ATCO Utilities submitted its application on March 16, 2015, no submissions or findings were made in respect of this direction.

ATCO Utilities submitted that it complied with directions 1 through 6 in Decision 2954-D01-2015, submitting a minor update to its operations and maintenance amounts and capital amounts allocations to reflect a 62 percent and 38 percent split, respectively. ATCO Utilities submitted that this updated allocation was consistent with Decision 2014-162.

ATCO Utilities submitted that the result of the reconciliation of amounts was a $1.481 million refund to ATCO Electric transmission customers, and a $0.419 million refund to ATCO Pipelines customers.

The AUC determined that it was prepared to accept ATCO Utilities' proposed allocation of pension costs. However the AUC directed ATCO Utilities in future applications to clearly demonstrate the calculation of the proposed allocators, and provide a justification for the proposed allocation, including any references to prior AUC decisions.

The AUC held that, based on the tables and information provided by ATCO Utilities, that ATCO Utilities had properly calculated the refund amounts associated with the reduction in the COLA amount. The AUC approved ATCO Utilities' compliance filing as filed and ordered:

(a) ATCO Pipelines to refund $0.419 million to its customers in its 2015-2016 general rate application in Proceeding 3577; and

(b) Ordered ATCO Electric's transmission function to refund $1.481 million as part of its upcoming 2013 deferral account application.

ATCO Gas and Pipelines Ltd., CU Inc. and Canadian Utilities Limited Disposition of the Calgary Service Centre Assets (Decision 20528-D01-2015)
Disposition of Assets

ATCO Gas and Pipelines Ltd. ("ATCO"), CU Inc. ("CUI"), and Canadian Utilities Limited ("CU") (collectively, the "Applicants") applied to the AUC to sell their Calgary Service Centre ("CSC") assets to ATCO Real Estate Holdings Ltd. ("ATCO REH") a wholly owned subsidiary of CUI. The Applicants sought approval for the disposition on the basis that the sale was outside the ordinary course of business and required AUC approval pursuant to section 26(2)(d) of the *Gas Utilities Act*.

The Applicants described the assets under consideration in the application as owned by ATCO, consisting of three adjacent properties located at 1040 – 11 Avenue S.W. in Calgary, Alberta. The Applicants further described the assets to be sold as follows:

Legal Description	Property Description
Lots 1-8, Block 64, Plan A1	North Parking lot, Shop/Garage and the Annex buildings
Lots 35 and 36, Block 64, Plan A1	East portion of the Office building
Lots 25-34 and 37-40, Block 64, Plan A1	West portion of the Office building and the East parking lot

(the "CSC Assets").

The Applicants submitted that the lots forming the CSC Assets were purchased between 1954 and 1962, with construction completed in 1963. The original cost and remaining book value of the CSC Assets was as follows:

Description	Historical Cost ($000)	Accumulated depreciation ($000)	Estimated net book value ($000)
Land	135	0	135
Building	4,575	(2,339)	2,239
CSC Grand Total	4,710	(2,339)	2,371

ATCO submitted that the annual operating costs of the CSC Assets was approximately $500,000, and identified needed improvements to the CSC Assets in 2014. The forecast cost of these improvements was approximately $4.3 million over three years. ATCO indicated that the forecast capital spending on the CSC Assets would be $470,000 in 2015, $1,790,000 in 2016, and $1,990,000 in 2017. ATCO had determined that it could provide the services currently provided by the CSC by more efficiently utilizing existing space at its other service centers, and therefore planned to discontinue using the CSC. ATCO expected relocation from the CSC to be complete by the end of October 2015. As a consequence, ATCO would be removing the CSC Assets from service regardless of the outcome of this decision. ATCO submitted that it would remove the net book value of the CSC Assets from rate base at the time of disposition.

The Applicants proposed the following transactional steps in disposing of the CSC Assets:

(a) ATCO would transfer the CSC Assets to ATCO REH in exchange for cash and preferred shares of ATCO REH;

(b) ATCO would then redeem the shares for a promissory note from ATCO REH;

(c) ATCO would in turn distribute the promissory note to its corporate parent, CUI., as a dividend;

(d) CUI would in turn distribute the promissory note on to CU as a dividend;

(e) CU would contribute the promissory note to ATCO REH as a subscription for additional common shares in ATCO REH; and

(f) ATCO REH would cancel the promissory note.

ATCO further noted that it planned to include relocation costs, as well as costs for renovation and expansion of its remaining service centers in rate base for its next capital true-up application, resulting in a net reduction of $0.9 million from rate base.

In response to an AUC information request, ATCO submitted that the CSC Assets were assessed at $19.64 million for municipal taxation services, and had an appraised market value of approximately $25.5 million.

The Consumers' Coalition of Alberta ("CCA") opposed the application on the basis that the proposed disposition was prompted by ordinary course of business concerns, namely deciding not to proceed with operations and maintenance costs.

The AUC determined that whether the disposition was inside or outside the ordinary course of business, it must be decided in the context of the proposed transactions. Accordingly, the AUC applied a test looking to the frequency and materiality of similar dispositions by the Applicants.

The AUC determined that ATCO's business is to provide gas distribution service, and that the sale of its service centers was not a normal occurrence, and had not occurred in the past 10 years. The AUC therefore held that the proposed transaction was outside the normal course of business, and required AUC approval.

Having found that the proposed disposition was outside the normal course of business, the AUC considered whether the proposed transaction met the no-harm test first set out in Decision 2000-41. The no-harm test requires that the disposition not harm consumers financially or with respect to service levels.

The AUC determined that it was not persuaded by the evidence that service quality would be unaffected, noting that the remaining service centers would be located in the suburbs of Calgary, which may impair response times to potential gas leaks in downtown Calgary. The AUC noted specifically that ATCO had failed to provide sufficient evidence in support of its claim that the relocation of the service center would have no impact on emergency response times.

With respect to impact on rates, the AUC held that the operating costs of $500,000 for the CSC put forth by ATCO were a fair representation of the operating costs. While the AUC was prepared to accept that the transaction would result in the reduction of the annual operating costs for the CSC, the AUC noted that it was troubled by ATCO's inability to state unequivocally that there would be no material increase in the operation costs of the remaining service centres.

With respect to the proposed capital expenditure forecast, the AUC expressed concern with the reasonableness of ATCO's forecast of $4.3 million over three years for the CSC Assets. The AUC noted that from 2005 to 2015, ATCO spent a total of $1,171,620 on repairs for the CSC, or an annual average of $117,000. ATCO's proposed forecast would increase this amount more than 10 times, to $1.4 million per year. The AUC noted that such increases should only be a consequence of sudden or unexpected failure of equipment. The AUC noted that the improvements largely fell into four categories:

(a) Interior work, for a total of $1,190,000 consisting of painting, flooring, millwork and finishing;

(b) Mechanical and electrical work, for a total of $1,030,000 consisting of HVAC upgrades, new lighting and fire system upgrades;

(c) Other work for a total of $1,050,000 consisting of installing a second floor elevator and removing asbestos floor tile; and

(d) General fees for a total of $780,000 consisting mostly of contractor costs, management fees, and architectural and interior design consulting fees.

The AUC held that these work expenses were not of an emergent nature, and could have been completed at any time by ATCO in the last few years. The AUC concluded that the nature of these costs called into question why ATCO would allow the CSC to fall into what the AUC described as a general state of dis-repair. The AUC therefore concluded that the forecast was generated to show that ratepayers would potentially experience lower rates due to a relocation of the CSC. The AUC set out its reasons for this conclusion, noting that ATCO only provided a one-page table in Appendix B to its application, but provided no supporting documentation to its cost forecast. The AUC further noted that a large percentage of the proposed costs appeared to be aesthetic in nature, and not for the provision of service. The AUC accordingly assigned little weight to ATCO's $4.3 million capital spending forecast.

The AUC further expressed concern with ATCO's forecast of $1.3 million for upgrades to its remaining service centers, noting that ATCO stated that the facilities could accommodate additional staff, but were not underutilized. Even accepting the $1.3 million forecast as reasonable, the AUC had difficulty ensuring that the disposition would not be harmful to customers in the long-term, as ATCO was unable to commit to what its longer-term space requirements could be as a result of the disposition. In noting the future growth forecasts provided by the City of Calgary on the record, the AUC expressed concern that the relocation to existing service centres may require further and more extensive renovations to the existing service centres, which will be borne by ratepayers. Therefore the AUC concluded that the risk of unknown future costs to ratepayers was high, and that ATCO had not met its onus of demonstrating that there would be no harm to consumers.

The AUC concluded by noting that it is ATCO's decision whether to proceed with removing the CSC Assets from utility service. However, the AUC stated that the law was clear, that in the event that ATCO removes the assets from service, they must be removed from rate base at that time. Given that ATCO had provided insufficient evidence for the AUC to determine whether the no-harm test was satisfied, the AUC held that it could not approve of the disposition of the CSC Assets.

The AUC therefore denied ATCO's application to dispose of the CSC Assets.

FortisAlberta Inc. 2013-2015 Capital Tracker Compliance Filing (Decision 20351-D01-2015)
Capital Tracker Compliance

In response to directions from the AUC provided in Decision 3220-D01-2015, FortisAlberta Inc. ("FAI") requested approval of its 2013-2015 Capital Tracker compliance filing. FAI's original 2013-2015 Capital Tracker application requested adjustments to its performance-based regulation ("PBR") rates through a "K Factor".

The PBR framework provides a formula mechanism to adjust rates annually, using inflation (I Factor) less an offset (X Factor) to reflect the productivity improvements the utility can expect to achieve during the test period. However, the PBR framework also requires certain adjustments, including amounts to fund necessary capital expenditures (K Factor), flow-through costs to be recovered directly from the consumer (Y Factor), and material events for which the company has no other reasonable cost recovery mechanism (Z Factor). Capital tracker costs form part of the K Factor adjustments within the PBR mechanism.

FAI submitted a summary table of the changes to its requested K Factor adjustments as a result of Decision 3220-D01-2015:

Capital Trackers K Factor Revenue ($ million)					
2013		2014		2015	
Applied for	Compliance filing	Applied for	Compliance filing	Applied for	Compliance filing
23.2	**17.4**	**48.1**	**42.2**	**68.9**	**62.2**

The adjustments submitted by FAI included reductions to the following programs:

(a) Customer Growth program;

(b) Alberta Electric System Operator Contributions program;

(c) Substation Associated Upgrades program;

(d) Distribution Line Moves program;

(e) Urgent Repairs program;

(f) Distribution Capacity Increases program;

(g) Worst Performing Feeders program;

(h) Pole Management program;

(i) Cable Management program;

(j) Distribution Control Centre/Supervisory Control and Data Acquisition project;

(k) Compliance, Safety, Aging Facilities, and Reliability program; and

(l) Metering Unmetered Oilfield Services project.

The AUC approved each of FAI's proposed adjustments as filed, finding that they were in compliance with the directions in Decision 3220-D01-2015.

FAI submitted it would recover the proposed rate adjustments in its 2016 annual PBR rates filing, which was submitted in September 2015. FAI proposed to charge carrying costs using its weighted average cost of capital on the difference between the placeholders and the requested K factor revenue amounts in its application, as follows:

Capital Tracker Amounts to be collected ($million)			
	2013	2014	2015
Closing balance – uncollected capital trackers	2.9	15.9	16.1
Mid-year balance	1.4	9.4	16.0
WACC	6.52%	6.64%	6.64%
Carrying Costs	**0.1**	**0.6**	**1.1**

The AUC, through an information request, inquired why the calculation of carrying charges for K Factor amounts should be granted a different treatment than for Y Factor and Z Factor amounts, which are calculated using AUC *Rule 023: Rules Respecting Payment of Interest* ("*Rule 023*"). FAI stated that such expenditures were financed using the weighted average cost of capital ("WACC") since the K Factor amounts themselves reflect capital investment, and that it was therefore appropriate to recover them using WACC calculations.

The AUC determined that both Y Factor and Z Factor amounts also recover costs that may be incurred on account of capital, and relied on its prior findings in Decision 2012-237 as a basis to treat K Factor amounts in a similar manner through AUC *Rule 023*. The AUC also noted that ATCO Electric Ltd., ATCO Gas and EPCOR Distribution & Transmission Inc. each used AUC *Rule 023* to calculate carrying charges on their respective K Factor amounts. For purposes of consistency, the AUC ordered FAI to calculate its K Factor amounts in a like manner for its 2016 PBR application.

In place of a separate rate rider, FAI proposed to reconcile the K Factor amounts for 2013-2015 as an addition to any 2016 K factor placeholder that may be applied in its annual PBR rate adjustment. FAI's proposed collection period would begin on January 1, 2016 and continue until December 31, 2016.

In response to an information request from the AUC, FAI submitted that it would not be opposed to extending its proposed collection period to 15 months, by beginning collection on October 1, 2015 to avoid rate shock. However, FAI cautioned that, due to rate changes in 2015, such an extension may produce a secondary impact on its irrigation customers, who have already experienced increases to rates in 2015.

The AUC held that the collection of the 2013-2015 K Factor amounts as part of its 2016 PBR rate adjustment would result in regulatory efficiency. In noting the potential additional impacts on FAI's irrigation customers, the AUC approved FAI's proposed collection period from January 1, 2016 to December 31, 2016.

The AUC ordered that the 2013 K Factor amount of $17.4 million for 2013 was approved on an actual basis. The 2014 and 2015 K Factor amounts of $42.2 million and $62.2 million respectively, were approved on a forecast basis.

The AUC further ordered FAI to include the collection of additional K Factor amounts associated with the 2013 actual, 2014 and 2015 forecast amounts (as well as any associated carrying charges) as part of its 2015 annual PBR rate adjustment application. As such, the AUC notified FAI that it would undertake an assessment of FAI's final bill impacts and approve the carrying costs as part of FAI's 2015 PBR rate adjustment application.

EPCOR Distribution & Transmission Inc. 2013 and 2015 K Factor True-up Rider (Decision 20559-D01-2015)
K Factor True-up Rider

EPCOR Distribution & Transmission Inc. ("EDTI") applied to the AUC for its 2013 and 2015 capital tracker true-up rider in accordance with Decision 3100-D01-2015 and Decision 20210-D01-2015, and requested the following amounts through "Rider DJ":

(a) The difference between the 2013 capital tracker forecast ("K Factor"), approved on an interim basis in Decision 2013-435, and the K Factor actual amount in Decision 20210-D01-2015;

(b) The difference between the 2015 K Factor placeholder, approved on an interim basis in Decision 2014-436, and the 2015 K Factor forecast approved in Decision 20210-D01-2015.

EDTI provided a table outlining its proposed K Factor true-up for 2013 and 2015 as applicable to each rate class as follows:

Rate Classes	True-up Amount ($)
1 Residential	(737,996)
2 Small Commercial	(172,174)
3 Medium Commercial	(163,102)
4 Time of Use	(320,565)
5 Direct Connects to	(164)
6 Time of Use - Primary	(84,654)
7 Customer Specific	(28,488)
8 Customer Specific, Totalized	(1,149)
9 Street Lights	(17,327)
10 Traffic Lights	(651)
11 Lane Lights	(638)
12 Security Lights	(12,603)
Total	(1,539,421)

EDTI did not request a true up for its 2015 K factor as part of this application.

EDTI proposed to apply its Rider DJ on a dollar per kilowatt-hour basis for each rate class, with the exception of Customer Specific rate classes and the Direct Connect rate classes. EDTI proposed a fixed charge per day for Customer Specific and Direct Connect rate classes.

The AUC determined that EDTI's calculation of the 2013 and 2015 K factor refund amounts were reasonable, and found EDTI's proposed allocation to each rate class to be consistent with past practice.

The AUC noted that Rider DJ was calculated using EDTI's 2016 forecast billing determinants, which will be tested as part of Proceeding 20821. The AUC held that, should it approve a different billing determinant than as applied for, the AUC will provide direction to EDTI on how to modify Rider DJ in that decision.

The AUC therefore ordered EDTI to refund the 2013 and 2015 K Factor true-up amounts in the amount of $1.54 million, inclusive of carry costs through its Rider DJ, effective January 1, 2016 to March 31, 2016.

AltaGas Utilities Inc. 2015 Net Deficiency and Rider F (Decision 20695-D01-2015)
Net Deficiency – Rider F

AltaGas Utilities Inc. ("AltaGas") applied for approval to implement its rate Rider F, for collection of AltaGas' net deficiency in October and November 2015, for all rate classes save the irrigation rate classes. AltaGas proposed to collect the Rider F amounts from irrigation customers in October 2015, only.

As part of its application, AltaGas requested approval of the following in Rider F:

(a) The uncollected 2013 net deficiency Rider F balance of $32,026;

(b) The 2013 Y factor true-up refund of $37,197 for income tax temporary differences;

(c) The 2013 capital tracker K factor true-up adjustment amount resulting in a refund of $86,226, as determined in Decision 20176-D01-2015;

(d) The 2014 Y factor adjustment of $139,182 related to the recovery of the full year 2014 revenue requirement of Natural Gas Settlement System Code (NGSSC) phase one capital costs;

(e) The 2014 capital tracker deficiency K factor amount of $749,810, as approved in Decision 20176-D01-2015;

(f) The 2015 capital tracker deficiency K factor amount of $108,779, as approved in Decision 20176-D01-2015; and

(g) The reversal of the carrying charge refund related to AltaGas' K factor adjustments, as approved in Decision 2014-357, resulting in a collection of $7,679.

AltaGas submitted that its total 2015 net deficiency amounted to $914,053.

AltaGas proposed to collect the net deficiency amount from October to November 2015, and calculated its collection of Rider F amounts based on 2015 forecast distribution service revenues, excluding the default supply provider administration fee revenues. AltaGas proposed to apply Rider F to all distribution service rate classes, including default supply customers and customers served by competitive retailers. AltaGas' proposed collection period would likely result in rate-smoothing, since consumption levels typically do not increase until December, and the monthly rate increases during the collection period would for the most part, have an impact of less than 10 percent of monthly billings.

The AUC approved AltaGas' proposed allocation and calculation of Rider F amounts as they were consistent with prior approvals. With respect to rate-shock concerns, the AUC held that in terms of absolute dollars per month for typical customers (except for irrigation classes), the rate impacts were similar to previous revenue deficiency decisions and would not constitute rate shock. The AUC determined that a one-month collection period for irrigation rate classes was reasonable. The AUC arrived at this finding despite a total bill impact of greater than 10 percent, on the basis that irrigation service was not available in November, and the total dollar impact compared favourably to previous revenue deficiency applications. The AUC considered that the total bill impact would be reasonable, and therefore would not result in rate shock.

The AUC approved AltaGas' proposed two month net deficiency Rider F in the amount of $914,053. The AUC authorized AltaGas to collect Rider F effective October 1, 2015 to November 30, 2015 for all rate classes except irrigation, which is to be collected effective October 1, 2015 to October 31, 2015.

ATCO Gas and Pipelines Ltd. and ATCO Energy Ltd. Gas Utilities Act Code of Conduct Regulation Compliance Plans Part A – Interim Approval (Decision 20815-D01-2015)

Code of Conduct Compliance Plans

ATCO Gas and Pipelines Ltd. and ATCO Energy Ltd. (collectively "ATCO") applied to the AUC requesting approval of its proposed code of conduct compliance plans, under the *Gas Utilities Act Code of Conduct Regulation* ("*GUACCR*"). ATCO requested the approval on an interim basis, pursuant to section 30(1) and 31 of the *GUACCR*. ATCO submitted that ATCO Energy Ltd. would be unable to provide retail gas services to customers without an approved compliance plan in place. ATCO Energy Ltd. planned to enter the market in October 2015, and therefore requested the approval on an interim basis in order for it to enter the market in a timely manner.

The AUC held that the current compliance plans be approved on an interim basis, as there would be no harm to any potential party. The AUC could order subsequent changes to ATCO's compliance plans. The AUC noted that the interim approval does not relieve ATCO of its requirements to submit an audit plan as well as an annual compliance audit pursuant to the *GUACCR*.

The AUC granted the interim approval on the basis that it would be in the public interest for an additional retailer to enter the market for the 2015-2016 heating season.

Market Surveillance Administrator and TransAlta Corporation Application for Settlement of Proceeding 3110

Application for Settlement

On September 30, 2015, the Market Surveillance Administrator (the "MSA") submitted an application for a consent order to settle Proceeding 3110. In Proceeding 3110, the AUC found that TransAlta breached section 6 of the *Electric Utilities Act*, and sections 2(h), (j), and section 4(1) of the *Fair, Efficient and Open Competition Regulation*.

Under the terms of the consent order, TransAlta agreed to pay $56,248,357.28, comprised of the following components:

(a) The costs of the MSA's expert witness and legal fees in the proceeding in the amount of $4,327,542.97; and

(b) An administrative penalty of $51,920,814.31 consisting of:

  (i) A disgorgement payment of $26,920,814.31 pursuant to section 63(2)(b) of the *Alberta Utilities Commission Act* ("*AUCA*"); and

  (ii) An administrative monetary penalty of $25,000,000.00 pursuant to section 63(2)(a) of the *AUCA*.

The AUC will consider the application for the consent order at a later date that has yet to be determined.

NATIONAL ENERGY BOARD

Saint John LNG Development Company Ltd. Application for a Licence to Export and Import Natural Gas (Letter Decision September 3, 2015)
Letter Decision – Export and Import Licence

Saint John LNG Development Company Ltd. ("Saint John") applied to the NEB for:

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

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

Saint John requested the following terms for its Export Licence:

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

(b) Maximum annual export quantity of 8.12 billion cubic metres;

(c) Maximum term export quantity of 203.1 billion cubic metres;

(d) A point of export at the outlet of the loading arm of the LNG facility to be located in Saint John, New Brunswick; and

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

Saint John requested the following terms for its Import Licence:

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

(b) Maximum annual import quantity of 8.86 billion cubic metres;

(c) Maximum term import quantity of 221.51 billion cubic metres; and

(d) A point of import at which the Maritimes & Northeast Pipeline crosses the Canada-United States border near St. Stephen, New Brunswick or such other point as may be accessible over the term of the Import Licence.

Saint John submitted that the quantity of LNG proposed for export would not exceed the surplus remaining after allowance for foreseeable consumption in Canada.

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

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

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

GNL Québec Inc. Application for a Licence to Export Gas as Liquefied Natural Gas (Letter Decision August 27, 2015)
Letter Decision – Export Licence

GNL Québec Inc. ("GNL Québec") applied to the NEB for a licence to export natural gas in the form of liquefied natural gas ("LNG") and requested the following terms:

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

(b) Maximum annual export quantity of 18.52 billion cubic metres;

(c) Maximum term export quantity of 458.34 billion cubic metres;

(d) A point of export at the outlet of the loading arm of the LNG facility to be located in the port of Saguenay, also called the port of Grande-Anse in La Baie, Québec, Canada; and

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

(the "Export Licence").

The NEB held that it would issue the Export Licence to GNL Québec, subject to the approval of the Governor-in-Council. The NEB determined that the quantity of gas to be exported would not exceed the reasonably foreseeable requirements for use in Canada having regard to trends in the discovery of gas in Canada. The NEB agreed with GNL Québec's submissions in respect of the robust and integrated nature of natural gas markets in North America, noting that GNL Québec's submissions were consistent with the NEB's own market monitoring information.

While the NEB noted that the aggregate volume of LNG export licences granted to date represented a significant volume of LNG exports from Canada, it noted that many of the projects associated with the export licences face a very competitive market, and construction challenges. However, the NEB declined to speculate on which licences will be used or used to the full volume allowance, and noted that it determined each application on its own merits.

As part of the conditions of the Export Licence, the NEB approved a 15 percent annual tolerance, noting that the maximum term quantity of the licence is inclusive of the 15 percent tolerance amount. The NEB also accepted the request for a sunset clause of 10 years in length, noting it to be generally consistent with NEB practice.

The NEB issued the Export Licence to GNL Québec as requested, subject to approval of the Governor in Council, finding that the quantity of gas to be exported by GNL Québec would be surplus to Canadian needs.

Update on Trans Mountain Expansion Hearing Schedule (Hearing Order OH-001-2014)
Hearing Schedule Update

Further to our August 2015 issue of this report regarding the Trans Mountain Oral Hearings, the NEB released an updated schedule to the hearing, following its prior decision to strike evidence from the hearing record.

Pursuant to section 52(5) of the *National Energy Board Act*, the NEB announced that the period of September 17, 2015 to January 8, 2016 would be excluded from the 15 month legislated time limit to issue a decision once the application is deemed complete. As a result of the excluded period, the time limit for the NEB to issue its report to the Governor in Council is now May 20, 2016.

Trans Mountain was expected to file replacement evidence by September 25, 2015. The NEB interveners will file information requests in respect of the replacement evidence on October 20, 2015, to which Trans Mountain will respond on October 26, 2015.

The full revised hearing schedule can be found here.