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DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA ENERGY REGULATOR

Directive 074: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes Suspended (Bulletin 2015-11)
Bulletin – Directive – Oil Sands

The AER announced the suspension of *Directive 074: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes* ("*Directive 074*") effective immediately, including all associated approval conditions and reporting requirements. *Directive 074* will be replaced by the Tailings Management Framework for Mineable Athabasca Oil Sands ("TMF"), also effective immediately. The TMF is a new policy for regulating fluid tailings volumes and decreasing risks associated with the accumulation of fluid tailings in the landscape.

The AER notes that it expects operators to not make any material changes to their current tailings management programs that may be inconsistent with the TMF.

The suspension of *Directive 074* does not affect requirements under the *Public Lands Act*, the *Oil Sands Conservation Act*, the *Environmental Protection and Enhancement Act*, the *Water Act*, and the Lower Athabasca Regional Plan. In addition, the suspension of *Directive 074* does not affect any federal requirements, approvals or conditions.

Issuance of Subsurface Order No. 3 Regarding the Duvernay Zone (Bulletin 2015-12)
Bulletin – Subsurface Order

The AER announced the issuance of Subsurface Order No. 3 regarding the Duvernay Zone ("Order"), which became effective April 1, 2015. The Order sets out the following subsurface rules and regulatory processes within the Duvernay in the area specified:

(a) There are no well density restrictions for both oil and gas drilling spacing units ("DSU").

(b) The target area for wells drilled within the standard drilling spacing unit for a gas or oil well must be the central area within the drilling spacing unit having sides 100 metres (m) from the sides of the DSU and parallel to them. Wells may be drilled across the boundaries of contiguous DSUs of common ownership.

(c) Defined pools within the order area will be subject to good production practice as reflected in the AER's maximum rate limitation ("MRL") order, provided that optimal depletion strategies are employed and wasteful operations are avoided.

(d) Initial pressure tests in accordance with *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells* ("*Directive 040*") are required to be taken at a minimum of one well per three section by three section area (square nine section area) measured from the wellhead location.

(e) Annual pressure tests in accordance with *Directive 040* are not required.

(f) Initial deliverability testing in accordance with *Directive 040* are not required.

(g) The requirements relating to the designation of a control well for production of gas from shale pursuant to section 7.025(2) of the *Oil and Gas Conservation Regulation* ("*OGCR*") and the requirements for conducting and reporting information pursuant to section 11.145(4) and section 11.145(5) of the *OGCR* are suspended.

(h) When required to take drill cutting samples within the zone pursuant to section 11.010 of the *OGCR* and *Directive 056: Energy Development Applications and Schedules*, a licensee must take the samples at an interval frequency no greater than 30 m within the zone.

A copy of the Order, and a map of the area to which it applies can be found here.

Licensee Liability Rating (LLR) Program Changes – Phase 3 (Bulletin 2015-13)
Bulletin – Licensee Liability Rating

The AER announced, in accordance with its previous Bulletin 2013-09, that it is implementing the third, and final, phase of changes to the Licensee Liability Rating (LLR) program (the "LLR Program"). The LLR Program will increase the well abandonment liability costs and industry average netback to the 2012 values, which was previously announced as effective before May 1, 2015. However, the AER announced a delay in implementation to August 1, 2015 to allow licensees time to prepare for the changes in light of market conditions.

The changes affect *Directive 011: Licensee Liability Rating (LLR) Program Updated Industry Parameters and Liability Costs* ("*Directive 011*") as follows:

(a) An increase to the deemed well abandonment liabilities by an additional one third towards the 2012 values, to bring them to the full 2012 values; and

(b) An increase to the deemed assets by an additional one third towards the 2012 industry average netback values.

The AER also noted that the LLR program management plan, announced in Bulletin 2014-06, allows licensees to pay the financial security owed in increments over a period of time.

ALBERTA UTILITIES COMMISSION

Stakeholder Consultation on the New Pipeline Need Section of Rule 020: Rules Respecting Gas Utility Pipelines (Bulletin 2015-05)
Bulletin – Rule 020 – Stakeholder Consultation

The AUC announced changes to AUC *Rule 020: Rules Respecting Gas Utility Pipelines* ("*Rule 020*"). *Rule 020* was approved on February 25, 2015 and became effective on March 16, 2015. An overview of the changes was set out in AUC Bulletin 2014-19.

Materials related to the consultation process, as well as a copy of the updated *Rule 020* are available here

Electric Transmission Project – Process Improvements: Amendments to Rule 007 to Streamline Need and Facility Application Requirements, and the Repeal of Rule 008 (Bulletin 2015-06)
Bulletin – Rule 007 – Rule 008 – Need – Facility Application

The AUC announced the repeal of AUC *Rule 008: Rules Respecting Use of Abbreviated Needs Process* ("*Rule 008*"), to be effective April 1, 2015. The AUC also announced a number of changes to AUC *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* ("*Rule 007*") to implement the recent amendment of the *Transmission Regulation*.

The *Transmission Regulation* was amended by the *Transmission Amendment Regulation* (AR 176/2014), which came into force on September 22, 2014. The amendments include the following:

(a) Certain exemptions to the requirement to file needs identification documents with the AUC for minor capital maintenance types of projects, minor system enhancement and upgrade projects, and certain types of connection projects;

(b) The creation of an independent system operator (ISO) abbreviated needs approval process which will replace certain AUC needs identification documents approvals;

(c) Clarification and amendment of the requirements with respect to needs identification documents and abbreviated needs identification documents still requiring AUC approval;

(d) The enabling of market participants to apply for approval from the AUC to construct transmission facilities and transfer them to the transmission facility owner; and

(e) The use of approved cost estimates.

The AUC noted that the reason for the repeal of *Rule 008* was that it was no longer being used, and not required. The abbreviated requirements will be incorporated into the needs identification document process set out in the revised *Rule 007*, for which consultation is still ongoing.

Since the AUC considers the outstanding changes to *Rule 007* to be straightforward with the implementation of the changes to the *Transmission Regulation* and the *Transmission Deficiency Regulation*, the AUC noted it would be implementing such further revisions without soliciting feedback from all stakeholders.

A copy of the revised *Rule 007* is available here.

AUC Rule 004: Alberta Tariff Billing Code Rules (Bulletin 2015-07)
Bulletin – Rule 004 - Tariff

The AUC announced the approval of changes to *AUC Rule 004: Albert Tariff Billing Code Rules* ("*Rule 004*"), which were approved on March 11, 2015, and will become effective April 1, 2015.

Since the approved changes involve system changes to tariff billing, the AUC will provide market participants time during 2015 to implement the changes required. The text of the update in *Rule 004* provides the AUC's rationale for the lag in implementation:

> This lag between the approval date and the implementation date is to recognize that the approved revisions to *Rule 004* will require industry stakeholders to make changes to their business processes and information technology systems in order to be compliant. The lag provides these entities the time to develop, implement and test their internal changes so that there is no disruption in the business processes once the revised changes are to take effect.

A copy of *Rule 004*, including stakeholder comments, AUC responses to stakeholder comments, and other background information relevant to the development of *Rule 004* can be found here.

AUC Rule 029: Applications for Municipal Franchise Agreements and Associated Franchise Fee Rate Riders (Bulletin 2015-08)
Bulletin – Rule 029 – Franchise Agreements – Franchise Fee Rate Riders

The AUC announced the approval of changes to AUC *Rule 029: Applications for Municipal Franchise Agreements and Associated Franchise Fee Rate Riders* ("*Rule 029*"). *Rule 029* was approved on February 25, 2015, and became effective April 1, 2015.

A copy of *Rule 029*, including stakeholder comments, AUC responses to stakeholder comments, and other background information relevant to the development of *Rule 029* can be found here.

Performance Standards for Processing Rate-Related Applications (Bulletin 2015-09)
Bulletin – Performance Standards – Rate-Related Applications

After conducting an internal review of application processes and performance standards, the AUC announced that, while it found a number of applications contained interrogatory steps, many did not require a process step for argument and reply argument. Consequently, the AUC announced that it would introduce a "basic written process" for certain applications filed on or after April 1, 2015.

Record development timelines for each application type were established on the basis that an applicant submits a thorough and detailed application, and the application process does not include technical meetings, motions, and other supplemental process steps.

The AUC noted that it remained committed to issuing disposition documents for all rate-related applications within existing timelines. A full listing of timelines and process types can be found here, in table 1 and table 2 of Bulletin 2015-09.

AltaLink Investment Management Ltd. and SNC Lavalin Transmission Ltd. et al. Proposed Sale of AltaLink, L.P. Transmission Assets and Business to Mid-American (Alberta) Canada Costs Award (Decision 3529-D01-2015)
Costs Award – Sale of Assets and Business

Subsequent to the issuance of Decision 2014-326, which approved the sale of AltaLink, L.P. ("AltaLink") transmission assets and business to MidAmerican (Alberta) Canada Holdings Corporation, the Consumers' Coalition of Alberta ("CCA") and ATCO Electric Ltd. ("ATCO") applied to the AUC for approval of $63,184.66 and $33,856.50, respectively, for legal services, various consulting fees, and other disbursements.

The AUC considered each of the cost claims pursuant to AUC *Rule 022: Rules on Intervener Costs in Utility Rate Proceedings* ("*Rule 022*"), as the proceeding in question related to a rate application.

The AUC held that ATCO was an ineligible intervener for claiming costs, since it registered to participate in the proceeding to "represent its interests as a transmission facility owner". The AUC also pointed to section 4 of *Rule 022*, which states "… the following types or classes of interveners are ineligible to claim costs: … (c) A utility intervening in another utility's application."

ATCO claimed that it was not intervening in a proceeding of another utility, but rather intervening in a proceeding involving companies that are involved in the proposed change of ownership of AltaLink. The AUC, however, rejected this argument, finding that the proceeding clearly applied to a regulated utility.

The AUC did consider whether it should, in the circumstances, exercise its discretion to allow ATCO's cost claim, despite the exclusion in *Rule 022*. The AUC held that it would not exercise its discretion to award costs, since *Rule 022* is permissive in nature, and does not create any obligation to award costs. The AUC also determined that claimants must prove an inability to raise financial resources to participate. The AUC accordingly declined to exercise its authority to award costs, finding that ATCO had the financial resources to participate in the proceeding, and disallowed ATCO's costs claim in its entirety.

With respect to the costs claim made by the CCA, the AUC found the hours and fees to be reasonable given the tasks described in the costs claim, and approved the CCA's costs claim in its entirety.

The AUC therefore ordered AltaLink Investment Management Ltd., MidAmerican (Alberta) Canada Holdings Corporation and SNC Lavalin to pay intervener costs to the CCA in the amount of $63,184.66.

ATCO Power Ltd. Decision on Preliminary Question – Application for Review of AUC Decision 2014-242: 2014 ISO Tariff Application and 2013 ISO Tariff Update (Decision 3494-D01-2015)
Review and Variance - Rule 016 - Alberta Court of Appeal

ATCO Power Ltd. ("ATCO") sought a review and variance pursuant to *Rule 016: Review and Variance of Commission Decisions* ("*Rule 016*") of Decision 2014-242, which dealt with the 2013 and 2014 ISO Tariff update. ATCO alleged three errors of fact, law and jurisdiction:

(a) Approving the rate applied to supply transmission service customers ("STS") and the rate applied to import opportunity service ("IOS") notwithstanding ATCO's concerns raised in the proceeding;

(b) Deciding that load shed service for imports ("LSSi") was an ancillary service under the *Electric Utilities Act* ("*EUA*"), and that LSSi costs are payable by demand transmission services rate customers under the ISO tariff; and

(c) Rejecting the rate proposal made by TransCanada Energy Ltd. ("TCE") to include "supply opportunity service" ("SOS") in the ISO Tariff.

On the first ground, ATCO submitted that the hearing panel erred in mischaracterizing ATCO's concerns about unduly discriminatory service between STS and IOS customers, as being about the operational requirements of ISO Rule 203.1, which imposes more onerous obligations on STS customers. ATCO also submitted that the hearing panel compounded on the previous error by dismissing such concerns as being more appropriately handled via the complaints process pursuant to section 25 of the *EUA*, thereby closing its mind to consideration of those issues.

A number of parties, including TCE and the Alberta Electric System Operator ("AESO"), submitted that ATCO had not established that any alleged errors could lead the AUC to materially vary or rescind the decision in question.

The AUC held that the first ground could not be substantiated, holding that the hearing panel made no decisions in respect of characterizing ATCO's concerns in any way. The AUC also held that the alleged error was not material or relevant to its ultimate determination that STS and IOS complied with legislative requirements. The AUC found that ATCO's submissions amounted to nothing more than "argument that the hearing panel failed to give certain parts of the evidence the weight desired by ATCO".

With respect to the second ground, ATCO submitted that the hearing panel incorrectly interpreted sections 17(a), (b), and 30 of the *EUA*, in addition to section 15, 16, and 17 of the *Transmission Regulation* by applying an incorrect interpretation of "satisfactory level of service" and by failing to distinguish between transmission access for intra-Alberta generators and transmission access for importers. ATCO also submitted that the hearing panel incorrectly interpreted "reasonable opportunity" for market participants to access the Alberta market to mean "unfettered access" for market participants.

The hearing panel determined that LSSi fell within the definition of "ancillary service" because LSSi is required by the AESO to provide a satisfactory level of service with an acceptable level of voltage and frequency.

The AUC determined that ATCO had not shown that an error in fact or law exists, holding that the hearing panel considered, but did not accept, ATCO's arguments on the same point. The AUC held that there was a sufficient legal and factual basis for the hearing panel to approve the allocation of LSSi in the ISO tariff.

With respect to the third ground, ATCO submitted that its argument was premised on the hearing panel having erred in fact or law in reiterating in the decision that there are no implicit or explicit transmission rights in Alberta.

The AUC held that, in the interest of regulatory efficiency, its decision on this point will be deferred until the appeal of AUC Decision 2013-025 is concluded or abandoned, noting that a similar ground was advanced in that case, and would likely receive consideration by the Alberta Court of Appeal.

In the result, the AUC dismissed the first and second ground of review, and deferred the third ground of review until such time as the Alberta Court of Appeal renders a decision in respect of AUC Decision 2013-025.

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

Generic Proceeding - Regulated Rate Tariff – Energy Price Setting

Direct Energy Regulated Services ("DERS"), ENMAX Energy Corporation ("EEC") and EPCOR Energy Alberta GP Inc. ("EEA") applied for 2014-2018 energy price setting plans ("EPSP") for their respective regulated rate tariffs ("RRT"). Each of DERS, EEC and EEA are regulated rate option ("RRO") providers. RRO providers are required to file monthly energy rates with the AUC, and as determined under the sections 103 and 104 of the *Electric Utilities Act* and the *Regulated Rate Option Regulation*. The RRO is required to be made available to customers within a service area as an alternative to purchasing electricity services from a retailer.

DERS, EEC and EEA all applied for a pre-tax reasonable return amount of $8.21 per megawatt hour (MWh) for the duration of the EPSP. The AUC denied this request, finding instead that the following all-inclusive after-tax return amounts were reasonable:

(a) $2.83/MWh for DERS;

(b) $2.44/MWh for EEC; and

(c) $2.51/MWh for EEA.

The AUC directed all three companies to file information setting the amount of return that is currently being collected through non-energy charges, and to express those as $/MWh amounts.

With respect to EPSP, DERS made the following requests and on which the AUC made the following findings:

(a) DERS applied to continue the use of block procurement through forward market hedge products. The AUC held that this was a reasonable proposal;

(b) DERS applied to have daily target prices for the forward market hedge products be set by an independent market consultant. The AUC denied this request and directed DERS to set the daily target prices;

(c) DERS applied to set hedge volume targets at the average load requirements. The AUC rejected this proposal, and directed DERS to file an analysis that justifies its hedge volume targets;

(d) DERS proposed no backstop and no self-supply. The AUC accepted the proposal for self-supply, but directed DERS to include a backstop provision in its EPSP;

(e) DERS applied to set the base energy charge using the weighted average price of its forward market hedges during the price setting period, and to gross up the base energy charge for any distribution line losses and unaccounted for energy. The AUC accepted these proposals; and

(f) DERS applied for 50 per cent of cost savings for any daily procurement below the daily target price to be for the credit of DERS. The AUC denied this proposal.

EEA made the following requests and on which the AUC made the following findings, for EEA's EPSP:

(a) EEA applied to acquire blocks of forward market hedge products through a series of six Natural Gas Exchange (NGX) auctions (plus one contingency auction) over the 120-day allowable price setting window. EEA also applied for seed prices for the NGX auctions to be determined on a confidential basis. The AUC accepted EEA's proposals;

(b) EEA proposed to retain a backstop supplier, and include the retainer cost as part of the monthly energy charge. The AUC denied this request, and directed EEA to include a different backstop mechanism; and

(c) EEA applied to set the base energy charge using the weighted average price of its forward market hedges during the price setting period, and to gross up the base energy charge for any distribution line losses and unaccounted for energy. The AUC accepted these proposals.

EEC applied to separate the pricing and procurements aspects in its EPSP application. EEC proposed to determine the base energy charge using the NGS Flat RRO 120 Index price, grossed up for any distribution line losses and unaccounted for energy. EEC proposed to manage its procurement entirely at the discretion of EEC's unregulated trading affiliate, EEC Wholesale Trading. The AUC denied EEC's proposed EPSP and directed EEC to file a new EPSP proposal.

With respect to risk compensation, DERS and EEA applied for commodity risk compensation ("CRC") based on a rolling weighted average historical systematic gains and losses over a 12-month period (with DERS proposing an addition of one standard deviation for volatility, and EEA proposing a fixed addition of 4.14 percent.) The AUC denied the request, and directed DERS to adopt an adaptive CRC methodology proposed by the Office of the Utilities Consumer Advocate ("UCA") which uses the same rolling weighted average, plus a fixed risk cycle component that is adjusted on a yearly basis.

DERS and EEA requested approval of other risk compensation ("ORC") in five areas: counterparty credit risk; billing error risk; customer class risk; recurring cost forecasting risk; and other administrative risk. The total ORC requested by DERS and EEA was \$0.43/MWh and \$0.80/MWh respectively. The AUC denied DERS' ORC requests in all areas. With respect to EEA's ORC requests, the AUC denied all areas except for recurring cost forecast risk, which the AUC approved \$0.07/MWh.

EEC applied for risk compensation for risk associated with load shape, and for the risk associated with residual forecasting of load. EEC proposed an auction process to price the load shape risk, and applied to set the residual forecasting risk compensation at 1.30 percent of the cost of average load. The AUC denied both proposals and directed EEC to file a new EPSP proposal.

Both EEA and DERS applied to have the EPSP term expire on April 30, 2018, which the AUC accepted as reasonable.

The AUC accordingly ordered filings for each of DERS, EEC and EEA as follows:

(a) DERS and EEA must file a compliance filing on or before April 13, 2015; and

(b) EEC must file a new proposal for its 2014-2018 EPSP on or before April 13, 2015.

AltaGas Utilities Inc. Rule 028 Natural Gas Settlement System Code Exemption (Decision 3606-D01-2015)
Exemption – Rule 028

AltaGas Utilities Inc. ("AltaGas") applied for exemptions from sections 2.11, 8.6.1.1 and 8.6.5.3 of AUC *Rule 028: Natural Gas Settlement System Code Rules* ("*Rule 028*") for the period of January 26, 2014 to December 31, 2015, which are:

(a) 2.11 – Timing of meter reads;

(b) 8.6.1.1(b) – Daily cumulative meter ("DCM") consumption transaction – process rules and content; and

(c) 8.6.3.2 – Select Retailer Notifications ("SRN") Table 9, Sequence 8, Profiling Class.

AltaGas explained that after version 1.3 of *Rule 028* became effective on January 26, 2014, AltaGas identified a discrepancy in the profiling classes it uses for natural gas settlement for Select Retailer Notification and Wholesale Settlement Details classes. AltaGas submitted that it would be unable to comply with requirements associated with these classes when TransAlta deems its meter reads. In subsequent meetings with AUC staff and other stakeholders, AUC staff suggested that AltaGas apply for an exemption to the specific sections of *Rule 028* until such time as it was able to comply, thereby avoiding potentially expensive temporary solutions.

AltaGas submitted that it planned to upgrade its customer information and billing system within three to five years, and its compliance with *Rule 028* would be managed in concert with those upgrades.

Section 2.11 of *Rule 028* requires utilities to deem their meter reads for DCM on the date that the meter was read, whereas AltaGas' systems deemed the meter read on the day after the meter was read. AltaGas submitted that it had held discussions with its retailers that there would be no impact from AltaGas' continued processes until a new billing system is implemented. Section 8.6.1.1 also requires that a deemed value for DCM be from the date the meter was actually read.

The AUC held that AltaGas currently does not report the time of day for meter readings as the actual meter read time, but instead reports the time of day for meter readings as a deemed meter read time on the next day. The AUC noted that there were no major impacts on customers or retailers, and that no parties had opposed the exemption request. The AUC therefore held that an exemption from Section 2.11 and Section 8.6.1.1(b) was appropriate.

With respect to Section 8.6.3.2, AltaGas explained that the profiling class data that it publishes in the SRN differs from the profiling class data in the Wholesale Settlement Details, and that it currently uses a manual email based confirmation system for each successful enrolment by a retailer to inform them of the correct profiling class. AltaGas submitted that this process is expected to continue until the new customer information and billing system is implemented. AltaGas submitted that this workaround process should prevent error correction requests on its system.

The AUC agreed that the workaround would limit the number of error correction requests, but directed that in any subsequent exemption applications, that AltaGas provide a description of the number of error correction requests, along with reasons associated for each occurrence.

ENMAX Power Corporation Large Distributed Generation D600 Rate Schedule Update Application (Decision 3581-D01-2015)
Rate Schedule Update Application

ENMAX Power Corporation ("EPC") applied to the AUC for approval to implement a revision to its Large Distributed Generation D600 rate schedule ("D600"). EPC requested that D600 become effective the month following the AUC's decision on the application.

EPC proposed, as part of the D600 rate, to continue the flow-through of system access service costs from the Alberta Electric System Operator ("AESO") through its distribution tariff. The AUC had previously approved this flow-through arrangement for D600 in Decision 2010-151.

EPC stated that there is now a possibility that D600 customers could export onto the transmission system, and as a result, EPC may have to hold supply transmission service ("STS") contracts at certain points of delivery, in addition to demand transmission service ("DTS") contracts. EPC submitted that its proposed flow through was consistent with other distribution providers, such as FortisAlberta Inc.'s Option M Distribution Credit/Charge.

The AUC, noting that no intervener's took issue with the proposal, approved the revised rate schedule effective April 1, 2015. The AUC also held that if EPC is required to hold an STS contract prior to April 1, 2015, it shall flow-through the STS costs to the transmission access deferral account in the interim.

2013 Generic Cost of Capital (Decision 2191-D01-2015)
Generic Cost of Capital

The AUC initiated Proceeding ID No 2191 to assess the 2013 Generic Cost of Capital ("GCOC"). The reasons provided by the AUC pertaining to the GCOC apply to the following utilities:

(a) AltaGas Utilities Inc.;

(b) AltaLink Management Ltd.;

(c) ATCO Electric Ltd.;

(d) ATCO Gas;

(e) ATCO Pipelines;

(f) ENMAX Power Corporation;

(g) EPCOR Distribution & Transmission Inc.;

(h) FortisAlberta Inc.; and

(i) TransAlta Corporation ("TransAlta"),

(collectively, the "Alberta Utilities", except TransAlta).

All of the above utilities participated in the GCOC proceeding, in addition to the Office of the Utilities Consumer Advocate ("UCA"), the Consumers' Coalition of Alberta ("CCA"), the Canadian Association of Petroleum Producers ("CAPP"), and the City of Calgary ("Calgary"). The decision also affects the following utilities that did not participate in the GCOC proceeding:

(a) EPCOR Energy Alberta GP Inc. ("EEA");

(b) ENMAX Energy Corporation ("EEC");

(c) Direct Energy Regulated Services ("DERS");

(d) City of Lethbridge;

(e) City of Red Deer; and

(f) Investor-owned water utilities regulated by the AUC.

The return on equity ("ROE") and debt to equity ratios do not apply to EEA, EEC or DERS, as those utilities are regulated pursuant to the *Electric Utilities Act Regulated Rate Option Regulation* and the *Gas Utilities Act Default Gas Supply Regulation*.

The AUC approached the decision in a similar fashion to its previous GCOC decisions, such as Decision 2011-474, by establishing a generic ROE that uniformly applied to all the affected utilities, and thereafter applying adjustments to the capital structure of each utility according to their respective business risks.

In establishing a fair ROE for the utilities, the AUC evaluated changes in the global and Canadian financial environment since the last GCOC proceeding, then sets a benchmark generic ROE. Impacts from the Utilities Asset Disposition proceeding (Decision 2013-417 (the "UAD Decision")), and from the implementation of the performance-based regulation ("PBR") mechanism for several of the distribution utilities are considered in addition to the generic ROE.

Changes in Global Economic and Canadian Capital Market Conditions

With respect to changes in global economic and Canadian capital market conditions since the last GCOC, the Alberta Utilities set out that despite declines in risk since 2011, the "systemic risks" remained higher than the 2008-2009 crisis, citing abnormally low bond rates as a sign of non-normal market conditions. Most other interveners argued that the financial risks from the 2008-2009 crisis have abated or stabilized, pointing to rate stability for A-rated utility yield spreads since 2011.

The AUC held that the global economic and Canadian capital market conditions had improved since the last GCOC proceeding, noting that the bond yield spreads were no longer elevated, indicating a return to normal economic conditions.

Capital Asset Pricing Models

With respect to establishing a generic ROE, the AUC considered a wide range of tests, including, capital asset pricing models ("CAPM").

The CAPM accounts for both the time-value and risk-value of money, by establishing a risk-free rate equivalent to investments in risk-free security, and then calculating a risk premium to reflect the possibility that the expected return may not be achieved. CAPP supported the application of the CAPM, citing its widespread use in financial analysis. The Alberta Utilities offered a variation of the CAPM, which they referred to as a risk-adjusted equity market risk premium test, which incorporates discounted cash-flow ("DCF") methods.

The AUC held that in arriving at its generic ROE, it would ascribe notable weight to the CAPM among the alternatives put forth in the GCOC proceeding, as it determined the CAPM to be a theoretically sound and useful tool for estimating ROE.

Risk-Free Rate

In assessing the risk-free rate, the Alberta Utilities offered a risk-free rate of 4.0 percent, based on the consensus forecasts for 10-year government of Canada bond yields, and adding a spread of 45 basis points to account for both recent and historic yield spreads on the government of Canada bond yields. The CCA supported this risk-free rate. CAPP submitted that a risk-free rate of 3.6 percent was more appropriate, taking into account the recent bond buying program in the United States depressing interest rates generally. The UCA submitted that risk free rates were in the range of 2.4 to 3.2 percent for 2013, 3.1 to 3.9 percent for 2014, and 3.3 to 4.1 percent for 2015, based on the December 2013 consensus forecasts, and assuming a 50 basis point spread of long-term bond yields over 10-year yields persists through 2015.

The AUC held that a reliance on consensus forecasts of long-term government of Canada bond yields to estimate the risk-free rate was reasonable. The AUC also held that the Alberta Utilities' upward adjustment to the risk-free rate had the potential to result in over-compensation. Therefore, the AUC considers the actual long-term rate of 2.8 percent to be a reasonable lower bound estimate, and 3.7 percent to be a reasonable upper bound of the risk-free rate.

Market Equity Risk Premium

In addressing the market equity risk premium, the AUC cited the general overlap of expert conclusion on this area, and determined that a risk premium of approximately 5.0 to 6.0 percent above the risk-free rate was appropriate. Therefore, the AUC determined that a long-run historical market equity risk premium of 5.0 percent continued to be a reasonable lower bound for the risk premium in the CAPM, but due to the persistence of low interest rates, the AUC accepted that a reasonable upper bound was 7.0 percent for the market equity risk premium.

The AUC continued to apply a "flotation allowance" of 50 basis points to provide an additional margin of safety for utilities when raising financing.

As a result, the AUC held that the CAPM ROE would be between 5.80 percent and 8.75 percent, using the lower and upper bounds of each component in the CAPM.

DCF Model

The AUC also considered the DCF model in developing a generic ROE. The DCF model uses two components: the dividend yield, and an expected growth in dividends and earnings.

The Alberta Utilities argued that the AUC should provide greater weight to the DCF model, pointing to "clear systemic problems of the CAPM." However, CAPP opposed placing such weight on the DCF model, noting that the expert evidence provided by the Alberta Utilities, assumed unreasonably high growth rates.

The AUC held that the DCF model is a relevant, and theoretically well-grounded economic method for estimated ROE. However, the AUC noted that it was less widely used than the CAPM, and that there was significant disagreement as between the parties on the variants of DCF used, and the outcomes predicted by each.

ROE and Adjustments or Modifications

The ultimate range of ROE recommendations by each of the parties was as follows:

(a) Alberta Utilities – ROE of 10.50 percent for 2013, 2014, and 2015;

(b) UCA – ROE of 6.78 percent for 2013, 7.27 percent for 2014, and 7.42 percent for 2015; and

(c) CAPP and CCA – ROE of 7.50 percent for 2013, 2014, and 2015.

Taking into account all of the above, including the reasonable lower and upper bounds recommended by each of the different tests, the AUC determined that a generic ROE of 8.3 percent was reasonable for each of 2013, 2014 and 2015.

In assessing whether any modifications to the ROE were necessary as a result of the UAD Decision, the AUC determined that in theory, the utility shareholders have been subject to a greater degree of risk than they were prior to the outcome of the UAD Decision. However, the AUC also noted that, if the risk were perceptible, the investing public would have created an increase in credit spreads for the Alberta Utilities, which was not supported by the evidence on the record. Therefore the AUC determined that no such adjustment was necessary at this time.

The AUC also considered whether the introduction of PBR required any adjustment to the ROE. The AUC noted that while PBR does impose some degree of risk, the adoption of the ability for utilities under PBR to apply for capital tracker amounts and various other pass-through costs did not significantly affect the cost of capital enough to require an adjustment to the generic ROE.

The AUC lastly considered whether to implement an automatic adjustment mechanism to its generic ROE for 2013, 2014 and 2015. The AUC noted that the parties were in agreement that if such a formula were to be adopted, it must account for changes in government bond yields, and changes in utility bond spreads. However, the Alberta Utilities did not support the implementation of such an adjustment until government of Canada long-term bond yields exceeded 4.0 percent. The AUC held that it would not implement an automatic adjustment mechanism at this time, but noted that such a mechanism may be warranted if market conditions warrant it at some later date.

Capital Structure of Utilities

As the second part of its GCOC determinations, the AUC considered the capital structure of each of the utilities regulated by the AUC. In particular, the AUC noted that its determinations affected the allowed percentage of rate base, net of no-cost capital, which was supported by common equity, as opposed to debt. The AUC's approach was to analyze the equity ratios that are required for the affected utilities to target credit ratings in the A-range. The AUC noted that in Decision 2009-216 and 2011-474, it observed the following minimum credit metrics as associated with A-grade credit ratings:

(a) Earnings before Interest and Taxes ("EBIT") coverage of 2.0 times;

(b) Funds from Operations ("FFO") coverage of 3.0 times; and

(c) FFO/debt ratio of 11.1 to 14.3 per cent.

The Alberta Utilities requested increases of two percent to their equity ratios, compared with the AUC's determinations in Decision 2011-474. The prior approved equity ratios, and equity ratios recommended by the Alberta Utilities are as follows:

	Last Approved (%)	Alberta Utilities (%)	UCA (%)	CCA (%)
ATCO Electric	37	39	33-35	35
AltaLink	37	39	33-35	35
ENMAX	37	39	35	35
EPCOR	37	39	35	35
ATCO Pipelines	38	44.5	33	35
ATCO Electric (Distribution)	39	41	36	37
ENMAX (Distribution)	41	43	38	39
EPCOR (Distribution)	41	43	38	39
ATCO Gas	39	41	36	35
FortisAlberta	41	43	38	39
AltaGas	43	45	40	41

The City of Calgary also requested lower equity ratios, arguing that higher equity ratios only serve to benefit equity holders. The AUC disagreed with this approach, and held that the purpose of setting an allowable equity ratio was to minimize debt costs, which are eventually borne by ratepayers, and the primary vehicle for ensuring low cost debt is to allow increased equity.

In setting equity ratios, the AUC applied its prior method in determining minimum equity ratios needed to satisfy all three credit metrics set out above. In examining updated data in respect of each credit metric, the AUC determined the minimum (and maximum) equity ratios for each credit metric, as follows:

(a) EBIT coverage of 2.0 requires a minimum equity ratio of 33%;

(b) FFO coverage of 3.11 requires a minimum equity ratio of 33%; and

(c) FFO/debt percentages of 11.29 and 14.32 percent require a minimum equity ratio of 34%, and allows for a maximum equity ratio of 43%.

In considering that these updated requirements were somewhat lower than those approved in Decision 2011-474, the AUC held that a reduction of one percent for distribution companies (prior to company specific adjustments) was warranted, and was also sufficient for companies to maintain an A-range credit rating for an average risk utility. For tax exempt utilities, the AUC determined that a continuation of adding two percentage points to the equity ratio of non-taxable utilities and to FortisAlberta (who does not collect income taxes in its revenue requirements) was reasonable.

On company specific matters, ATCO Pipelines argued its risks had increased since the last GCOC proceeding, owing to its integration with NOVA Gas Transmission Ltd. ("NGTL"), and requested a 6.5 percent increase to its equity ratio. CAPP disagreed with ATCO Pipelines' request, noting that ATCO Pipelines' revenue requirement was now being recovered as a monthly charge in NGTL's tolls, and functionally had the same risk level as NGTL's junior subordinated debt, which CAPP submitted was quite low. CAPP therefore submitted that the increase to ATCO Pipelines' equity ratio was not needed.

The AUC held that ATCO Pipelines' risk had not changed since Decision 2011-474. While the AUC acknowledged that some costs may not be recovered through the AUC, this was acknowledged as a risk common to all utilities, and was not unique to ATCO Pipelines. The AUC determined that no changes were necessary to ATCO Pipelines' equity ratio relative to the other utilities in the GCOC proceeding.

Approved Equity Ratios

The AUC determined that the equity ratios for each of the utilities be approved at the following levels, finding that no company specific changes were required, save for a one percentage point increase to TransAlta (which effectively maintained their equity ratio at 36 percent):

	Last Approved (%)	2013-2015 Approved (%)	Change (%)
ATCO Electric	37	36	-1
AltaLink	37	36	-1
ENMAX	37	36	-1
EPCOR	37	36	-1
Red Deer	37	36	-1

Lethbridge	37	36	-1
TransAlta	36	36	0
ATCO Pipelines	38	37	-1
ATCO Electric (Distribution)	39	38	-1
ENMAX (Distribution)	41	40	-1
EPCOR (Distribution)	41	40	-1
ATCO Gas	39	38	-1
FortisAlberta	41	40	-1
AltaGas	43	42	-1

The AUC noted that these equity ratios were approved on a final basis for 2013 through 2015 and would also remain in place on an interim basis for 2016 and subsequent years, until changed by the AUC.

Accordingly, the AUC directed the Alberta Utilities to adjust their rates to implement the findings of this decision.

ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. 2015 Interim Revenue Requirement (Decision 3586-D01-2015)
Interim Revenue Requirement

ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. ("ATCO") requested approval for an interim monthly fixed fee of $17,724,000 per month, to be effective January 1, 2015, reflecting 100 percent of ATCO's forecast 2015 revenue requirement, representing an 11 percent ($22.1 million) increase over its $192.6 million final revenue requirement for 2014, as approved in Decision 2014-162.

ATCO also filed its general rate application on December 13, 2014, requesting revenue requirements of $214,728,000 and $250,362,000 for 2015 and 2016 respectively.

ATCO submitted that it required 100 percent of its 2015 revenue requirement on the basis that the increase was mostly attributable to a single project, being the urban pipelines replacement capital expenditure program ("UPR"). ATCO further submitted that it did not believe there to be any contentious issues or costs that might need to be removed from the interim revenue requirement application.

However, the Office of the Utilities Consumer Advocate ("UCA") and the Consumers' Coalition of Alberta ("CCA") both cited the UPR, licence fees, and I-Tek (ATCO's information technology provider) costs to be contentions and in need of further examination.

ATCO submitted that the UPR costs had already been established, and were the most significant cost drivers in the application. However, the UCA and CCA took issue with this characterization, noting that ATCO intended to re-bid the cost of one of the UPR projects in Northeast Calgary. Given the increased cost forecasts given by ATCO, the UCA and CCA argued that the original cost forecast from ATCO should be applied in the interim, until the final costs can actually be established. ATCO replied, citing that such an approach would account for only 13 percent of the requested revenue requirement increase for 2015.

With respect to information technology costs, the UCA argued that information technology costs were contentious, given is concerns with the new Master Services Agreements and their potential impacts on ATCO's operating costs.

ATCO submitted that the information technology costs have not been finalized, and were included as a placeholder amount, and the interim amount requested was lower than that of the placeholder included in the 2015 revenue requirement.

With respect to licence fees, ATCO noted that the costs for licences were a new cost included, and amounted to approximately $628,000, or less than three percent of the requested revenue requirement increase.

The UCA and CCA argued that the inclusion of these new costs were contentious, given that both parties intended to test the inclusion of licence fees in ATCO's general rate application for 2015 and 2016.

ATCO submitted that approval of 100 percent of the requested revenue requirement was needed to continue supporting capital and operating maintenance programs, and would otherwise impose a short-term cash shortfall that ATCO described as not sustainable or fair. However, ATCO noted that even if the interim increase was not granted, its return on equity would remain above zero, and that such a shortfall would in fact not have an immediate impact on its ability to provide safe and reliable service.

The UCA and CCA submitted that an interim revenue requirement increase of 50 per cent of the requested amount would therefore be appropriate in the circumstances.

Overall, given the quantum of increase and the need for ATCO to avoid potential shortfalls in the short term, the AUC found that an increase to a portion of the requested increase was warranted. However, given the submissions of ATCO on the effects of an increase of less than the full amount, and the contentiousness of the items listed above, the AUC held that ATCO had not demonstrated that an increase of less than 100 percent of the requested amount would impose financial hardship on ATCO.

Therefore, the AUC determined that ATCO's interim rates should reflect an increase of 60 percent of ATCO's 2015 forecast revenue requirement increase, or $17,157,800 per month after adjustments. The AUC held that these interim rates would become effective on April 1, 2015, and would continue in effect until such time as varied by either a new interim rate or a final rate.

AltaLink Management Ltd. Application for Exemption Order for Long-Term Debt Applications (Decision 3532-D01-2015)

Exemption – Public Utilities Act - Long-Term Debt Application

AltaLink Management Ltd. ("AltaLink") applied for an exemption order for long-term debt applications pursuant to Section 101 of the *Public Utilities Act* ("*PUA*") declaring that:

(a) Section 101(2)(a)(ii) of the *PUA* does not apply to AltaLink and AltaLink in its capacity as general partner of AltaLink L.P.("ALP") in respect of the issuance of medium term notes having maturities of not less than one year from the date of issue (the "Notes") in an aggregate principal amount of up to $2 billion; and

(b) Section 101(2)(d)(i) of the *PUA* does not apply to AltaLink in respect of AltaLink as legal owner, to cause ALP, as beneficial owner, to grant security to its lenders for the notes in the form of a first floating charge over the present and future property, assets and undertaking of AltaLink.

AltaLink submitted that the order as requested would not pose a risk to rate payers and would provide AltaLink with the necessary flexibility to manage its capital requirements in a timely and efficient manner, and would ensure lower costs to raise debt. AltaLink requested that the order apply for an exempt financing period matching its 2015-2016 general tariff application.

The Office of the Utilities Consumer Advocate ("UCA") raised two general concerns:

(a) Whether it was necessary for AltaLink to issue the Notes in currencies other than Canadian dollars; and

(b) Whether it was necessary for AltaLink to have the ability to use the net proceeds for purposes other than those enumerated in the exemption request.

The UCA submitted that AltaLink had not demonstrated that the issuance of the Notes in currency other than Canadian dollars was in the public interest.

AltaLink did acknowledge that a higher risk to ratepayers may result in issuing Notes in a currency other than Canadian dollars, however, AltaLink also noted that the AUC previously approved a similarly worded exemption request in Decision 2013-407. AltaLink also submitted that it did not have plans to issue notes in currencies other than Canadian dollars, but was only included in the case that Canadian debt markets were unaccommodating to AltaLink's issuance of Notes for reasons beyond its control. AltaLink submitted that without such flexibility, the AUC would be imposing a risk that AltaLink may have to raise capital on unfavourable terms.

AltaLink submitted that the exemption is necessary, due to the following anticipated circumstances during the exempt financing period:

(a) Substantial and unprecedented capital expenditures;

(b) Capital expenditures and financing requirements to remain at elevated levels;

(c) Potential volatility of capital market conditions;

(d) Existence of favourable market conditions for periods shorter in duration than what is required to obtain prior regulatory approval; and

(e) Access to capital markets affected by competing offerings of secured debt securities, which do not have the same degree of regulatory requirements.

The AUC held that the ability to issue debt in foreign currencies can provide AltaLink with flexibility to manage its capital requirement in a timely and efficient manner in the event that problematic capital market conditions develop. The AUC determined that such flexibility would facilitate AltaLink's ability to obtain the lowest cost blend of borrowing terms to meet its capital and refinancing requirements. Accordingly, the AUC found that AltaLink's request for an exemption extending to issuances of debt in foreign currency was in the public interest.

However, the AUC cautioned that this exemption did not constitute an advance assessment respecting the prudency of any such foreign currency transactions, which would be subject to later review by the AUC at AltaLink's next general tariff application.

The AUC also determined that the UCA's concerns with respect to the potential uses to which AltaLink could put its debt issuances was not necessarily a cause for concern, as it held the possibility of such other uses to be remote.

Accordingly, the AUC ordered that, pursuant to Section 101(4) of the *PUA*:

(a) Section 101(2)(a)(ii) and Section 101(2)(d)(i) of the *PUA* do not apply to AltaLink for the purposes as requested by AltaLink; and

(b) Nothing in the order shall bind, affect or prejudice the AUC in any way in its consideration of any other matter or question relating to AltaLink.

Summary of Capital Tracker Application Decisions
Capital Tracker

In March, 2015, the AUC released the following three decisions related to capital tracker applications:

(a) Decision 3220-D01-2015 regarding FortisAlberta Inc. ("FAI") 2013-2015 PBR Capital Tracker Application;

(b) Decision 3218-D01-2015 regarding ATCO Electric Ltd. ("ATCO Electric") 2013 PBR Capital Tracker Refiling and True-up and 2014-2015 PBR Capital Tracker Forecast; and

(c) Decision 3267-D01-2015 regarding ATCO Gas and Pipelines Ltd. ("ATCO Gas") 2013 PBR Capital Tracker Refiling and True-up and 2014-2015 PBR Capital Tracker Forecast.

Pursuant to directions from the AUC arising from Decision 2013-435, FAI, ATCO Electric, and ATCO Gas applied for their respective 2013 capital tracker refiling and true-ups, as well as their respective 2014 and 2015 capital tracker forecasts. Briefly, the three respective applications were as follows:

(a) FAI applied for nine capital tracker programs in 2013, and an additional three in 2014 and 2015 respectively. FAI stated the total net impact of the applied for programs as: (i) $23.2 million for 2013, or 11% of total revenue requirement; (ii) $48.1 million for 2014, or 19% of total revenue requirement; and (iii) $68.9 million for 2015, or 24% of total revenue requirement;

(b) ATCO Electric applied for nine capital tracker programs in 2013, and an additional two in 2014 and 2015 respectively. The total net impact of the applied for programs was stated by ATCO Electric to be: (i) $ 21.6 million for 2013; (ii) $ 40.6 million for 2014; and (iii) $ 57.1 million for 2015; and

(c) ATCO Gas applied for 18 capital tracker programs. The total net impact of the applied for programs was stated by ATCO Gas to be: (i) For 2013, $9.559 million for the north, and $5.579 million for the south; (ii) For 2014, $15.645 million for the north, and $8.671 million for the south; and (iii) For 2015, $24.537 million for the north, and $14.582 million for the south.

<u>Background</u>

Capital tracker applications are part of the performance based regulation ("PBR") plans originally approved by the AUC on a five-year term in Decision 2012-237.

The PBR framework essentially provides a formula mechanism to adjust rates annually, using inflation (I Factor) less an offset (X Factor) (the "I-X Index Factor") to reflect the productivity improvements the utility can expect to achieve during the test period. The I-X Index Factor is further adjusted to account for forecast billing determinant growth ("Q Factor"). 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.

Projects or programs are eligible for capital tracker treatment, provided that they meet the following three criteria:

(a) The project must be outside the normal course of on-going operations ("Criteria 1");

(b) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party ("Criteria 2"); and

(c) The project must have a material effect on the company's finances ("Criteria 3").

In order to qualify as Criteria 1, the AUC noted that the increase in associated revenue provided by the PBR formula must be insufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the program or project in question. This test is therefore considered by the AUC as more accounting oriented than engineering oriented, although such applications must generally be supported by an engineering study and business case to assess the reasonableness of the request.

With respect to Criteria 2, generally a growth related project which can demonstrate that customer contributions and incremental revenues are insufficient to offset the revenue requirements associated with a project for a given PBR year will satisfy the requirements.

The materiality threshold in Criteria 3 requires that each project must individually affect the revenue requirement by four basis points. On an aggregate level, all proposed capital trackers must have a total impact on revenue requirement of 40 basis points.

Required Updates to I-X Index Factors and Q Factors

As part of Decision 2013-435, the AUC required that FAI, ATCO Electric and ATCO Gas update their I-X Index Factor and Q Factor.

The AUC held that FAI applied the proper weighted-average cost of capital and that its accounting test model was both reasonable and consistent with the methodology approved in Decision 2013-435. As the AUC recommended that FAI update its I-X Index Factor and billing determinants growth factors in forecasting its costs, due to the fact that updates to the I-X Index Factor and billing determinants would cause FAI's baseline costs to change, the AUC was not able to specifically approve any quantum of costs for any of the projects. The AUC therefore ordered a compliance filing.

The AUC held that all of the projects and programs met the second criteria insofar as they were externally driven, asset replacements or growth-related, on the basis that the AUC had previously approved such programs, or that there was no evidence to indicate that the projects and programs did not fit into the three categories.

The AUC held that ATCO Electric and ATCO Gas had reasonably applied the accounting test methodology approved in Decision 2013-435. However, for the purposes of applying the I-X mechanism, and the Q Factor, the AUC determined that ATCO Electric and ATCO Gas had applied various placeholders to the 2014 and 2015 values for the I factor and Q Factor. The AUC determined that the 2014 placeholder values were correct, but the 2015 values had to be estimated due to timing constraints associated with ATCO Electric and ATCO Gas' 2015 annual PBR filing. The AUC noted that Decision 2014-354 approved updated I factors and Q Factors for 2015, and directed ATCO Electric and ATCO Gas to use these updated figures in its accounting test for its compliance filing to this decision.

On matters related to assumptions used by ATCO Electric and ATCO Gas for weighted cost of capital, the AUC directed them to incorporate all changes to 2013, 2014 and 2015 weighted average cost of capital rates directed by the AUC in Decision 3434-D01-2015, and such further changes directed by the AUC in Decision 2191-D01-2015.

Project Groupings

On the issue of project and program groupings, the AUC held that the grouping of projects or programs for the sole purpose of minimizing or maximizing the capital tracker revenue amounts is contrary to the approved PBR mechanism. The AUC also noted that companies naturally have an incentive to group projects in such a way. However, where such groupings are consistent with past practice, there will not normally be a reason to question the reasonableness of such groupings, unless the groupings are not suitable for determining whether particular programs or projects are sufficiently similar to be grouped together for capital tracker purposes.

The AUC accepted that FAI's groupings were consistent with those approved in its previous distribution tariff application. The AUC also noted that FAI had complied with the directions of the AUC to disaggregate certain projects in order to separate projects that were dissimilar. The AUC directed FAI to reconsider its groupings of projects within its Distribution Capacity Increases program and Metering Unmetered Oilfield project as part of its next capital tracker application, as the AUC held that the projects may not be sufficiently similar.

The AUC found that ATCO Electric's proposed project groupings were consistent with its prior general tariff applications. Accordingly, the AUC held that the projects were properly grouped, and that there was a need for the projects in order to provide and maintain service quality at adequate levels.

ATCO Gas stated that all of its groupings were approved by the AUC in Decision 2013-435, and that these groupings complied with the AUC directions. ATCO Gas submitted that it performed its grouping and accounting tests by separating its projects between north and south service areas, and performed the materiality test separately under Criteria 3 with respect to each. ATCO Gas stated that the basis for this separation is that it is required to maintain two separate PBR plans for the north and south.

The AUC determined that, until ATCO Gas is directed to implement a single, Alberta-wide rate model with a single rate base, ATCO Gas will maintain its current practice of separating rates for north and south.

The AUC found that ATCO Gas' proposed project groupings were consistent with its prior general rate applications. Accordingly, the AUC held that the projects were properly grouped, and that there was a need for the projects in order to provide and maintain service quality at adequate levels, with the exception of certain historically grouped costs in the Steel Mains Replacement program.

Project Assessment Under Criteria 1 and 2

The AUC noted that FAI had broadly applied for two categories of programs in its capital tracker application:

(a) Projects or programs which the AUC previously approved in Decision 2013-435; and

(b) Projects or programs implemented in 2013, or to be implemented in 2014-2015, for which the need has not been approved.

The AUC held that the common elements of FAI's 2014-2015 capital expenditure forecasts, including index escalators, growth rates, and housing starts, were all reasonable. The AUC also found that FAI's reliance on competitive procurement processes reassures the contention that the scope, level, timing and costs of the forecast capital projects are reasonable.

The CCA took issue with FAI's request for capitalization of overhead costs, noting that FAI was asking for capitalization of approximately $113 million over the course of three years, with what the CCA characterized as "limited or no details to support the request". The CCA also submitted that the capital tracker portion of capitalized overhead costs increased to 86% of the total in 2014, and were slated to increase to 87% in 2015.

The AUC agreed with the CCA, noting that FAI had not demonstrated that its capitalized overhead costs were prudent, as detailed information was not provided. Therefore, in the absence of such evidence supporting the overhead costs, the AUC declined to approve an increase in overhead costs in excess of the previous year's amount adjusted by the I-X mechanism.

The AUC directed FAI, in its compliance filing, to limit the total pool of overheads for each of 2013, 2014 and 2015 to the lower of the amounts in the application or the amounts reflected in the increases in the I-X mechanism, applied to the 2012 rates.

The AUC provided findings only on those projects that it determined were insufficiently addressed or were otherwise raised as an issue by interveners in the proceedings. All programs were approved as filed with respect to Criteria 1, unless otherwise noted.

The AUC also held that each of the proposed project groupings fell into one of the following three categories, as required by Criteria 2:

(a) Asset replacement or refurbishment;

(b) Required by an external party; or

(c) Growth related.

FAI - Worst Performing Feeders Program

FAI submitted that this program focuses on the repair and upgrade of sections of feeders on FAI's distribution system with the poorest reliability. FAI applied for the following amounts:

(a) $6.1 million in 2014; and

(b) $6.1 million in 2015.

The AUC noted that the Worst Performing Feeders program had previously been approved by the AUC in Decisions, 2008-011, 2010-309, and 2012-108, accordingly, it approved of the continued need for the program. However, the AUC also noted that AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors* only requires the replacement of the bottom three percent of feeders, and therefore, the AUC limited the scope of the program to the three percent of feeders with the worst performance record, and not any of the additional metrics proposed by FAI. The AUC invited FAI to re-apply for capital tracker treatment on these additional costs in its next true-up application.

Given the reduction in scope, the AUC also directed FAI to reconsider the materiality impacts of the Worst Performing Feeders program, as the additional costs disallowed represented half of the program costs, thereby reducing the increase to $3.0 million for each of 2014 and 2015.

FAI - Pole Management Program

FAI submitted that this was a grouping of capital projects designed to maximize the service life of existing poles, and replacement of poles failing inspections. FAI applied for the following amounts:

(a) $15.6 million in 2013;

(b) $31.4 million in 2014; and

(c) $39.9 million in 2015.

FAI noted that this program is undertaken in order to maintain its system and to provide service in a safe and reliable manner. FAI submitted that this program is necessary, as many of its poles constructed in the 1950s have service lives between 50 and 70 years, and many are at or near the end of those service lives and require replacement.

FAI explained the variances in previous years of forecasts, noting that it is able to accurately forecast the number of poles that will be tested for failure criteria (as one seventh of its poles are tested each year), but that the number that will pass or fail is inherently unknown.

The AUC noted that the program had not previously been approved for capital tracker treatment. The AUC held that the program was required to maintain service reliability and safety at adequate levels. The AUC held that the $11.7 million in actual capital expenditures in 2013 for pole replacements were prudent, however, there was insufficient evidence on the record to establish the prudence of the remaining $3.9 million in actual capital expenditures related to line-rebuild projects. Therefore, the AUC denied capital tracker treatment for the line-rebuild projects, and invited FAI to re-apply for these costs at a later date with the appropriate information.

Citing similar concerns with forecasts for 2014 and 2015 for line-rebuild projects, the AUC also denied capital tracker treatment for forecast line-rebuild costs in 2014 and 2015, and invited FAI to re-apply for these costs with appropriate information.

The AUC otherwise found that there was no evidence on the record to indicate that the Pole Management Program was not required for 2014 or 2015, and held that the scope level and timing of the program was reasonable.

The CCA submitted that the Pole Management program's seven year life cycle inspections had no credible support, noting that the reports relied on by FAI actually advocated a 10 year inspection cycle.

The AUC declined to rule on the appropriateness of the seven year inspection cycle. Given the historical use of this inspection cycle, and its current application under FAI's PBR term, the AUC noted it may address the issue at the end of the current PBR term.

FAI Deferral of 2013 Capital Spending

FAI applied for approval of its 2013 capital spending that was deferred. FAI noted that the deferrals were specific to Distribution Capacity Increases, Metering Unmetered Oilfield services, Worst Performing Feeders, Pole Management and CSAR programs. The total deferred capital spending for 2013 amounted to $34.9 million. FAI submitted that the deferrals did not impact service quality, and were instituted at a time when the accounting tests and materiality thresholds for capital tracker treatment were not yet known.

The AUC held that uncertainty as to the nature and extent of capital tracker treatment was not a valid business decision for deferring work. Nevertheless, the AUC recognized that 2013 was a transition year, and that the deferrals did not appear to have been made in order to affect the recovery of capital under the capital tracker mechanism. Accordingly, the AUC opted not to disqualify the five deferred programs from consideration for capital tracker treatment.

ATCO Electric - Buildings, Structures and Leasehold Improvements Program

This program involves the provision of office and warehouse facilities to meet ATCO Electric's current staffing needs and near term forecast additions of personnel and equipment. As part of this program, ATCO Electric applied to include the cost of the Drumheller Service Building. The CCA opposed the inclusion of the Drumheller Service Building, noting that ATCO Electric had applied for approval to construct a similar building in three previous general tariff applications, and that the cost had escalated from $10.057 million in 2009 to $30.08 million in its 2013-2014 general tariff application, to $37.6 million in this application. The UCA also noted that even if such costs are approved, that ATCO Electric has neglected to remove the costs of its administration building in Drumheller from rate base since 2009, and that the costs of removal should offset any increase from the Drumheller Service Building.

The AUC held that the Drumheller Service Building had been approved on three separate occasions, and had grown in scope in each successive application. The AUC accepted ATCO Electric's explanation for the project delays, noting that such factors were primarily outside of ATCO Electric's control. However, the AUC held that the increase in scope in this application was not substantiated on the record, and therefore denied the $7 million increase in costs as ATCO Electric had failed to demonstrate the project satisfied Criteria 1.

With respect to the omission in rate base, the AUC ordered ATCO Electric to remove the net book value of the administration building from rate base, and that any consequent changes be reflected in ATCO Electric's next PBR filing.

With respect to the Nisku Pole and Training Facility Development project, the AUC found that there was insufficient evidence with respect to the forecast scope, level, and timing of costs to determine if they were reasonable. However, the AUC stated it was not making a determination of the prudence of the 2013 costs incurred in respect of this specific project. For the remaining 2014 and 2015 forecast costs associated with this project, the AUC found that the project satisfied the requirements of Criteria 1, it did not have supporting evidence necessary to make a determination on the forecast scope, level, and timing of costs. The AUC invited ATCO Electric to re-apply for these costs once it has incurred all the capital expenditures associated with the project.

The AUC also denied capital tracker treatment to the cost of 6.2 acres of land purchased as part of capital expenditures for the Valleyview Service Building, as it held that the surplus land was not required for utility service in the near term. However, the AUC allowed ATCO Electric to apply for capital tracker treatment of such land should it become required to provide service in the future.

The AUC otherwise approved the Buildings, Structures and Leasehold Improvements Program as applied for.

ATCO Electric - Information Technology Program

ATCO Electric applied for the following amounts under the Information Technology program:

(a) $14.4 million for 2013;

(b) $24.2 million for 2014; and

(c) $15.9 million for 2015.

ATCO Electric submitted that the costs for Operations System Extension projects were generally driven by the customer growth and the maintenance of safe and reliable service related to its Outage Management System due to an increase in volumes of work and aging assets.

The AUC held that ATCO Electric had not satisfied the onus of demonstrating that the Operations System Extension projects were required to prevent deterioration in service quality and safety if the expenditures were not undertaken. Accordingly, the AUC denied capital tracker treatment for these costs for 2013, 2014, and 2015.

The AUC otherwise approved the Information Technology costs as filed, noting however that some of the costs applied for could have also been applied for as a Z factor or Y factor. The AUC found that ATCO Electric was not required to apply for recovery of costs under a specific factor, even if on a *prima face* basis, they should be recovered under a different factor, so long as the evidence before the AUC supports the recovery of costs as a capital tracker. Accordingly, the AUC held that it was within the discretion of the utility to apply for the recovery of costs under the factor it considered appropriate.

ATCO Electric - Overhead Line Rebuilds, Replacements and Life Extension Program

The CCA expressed concerns with ATCO Electric's Wood Pole Replacement and Life Extension program within this program group. The CCA argued that ATCO Electric uses higher depreciation rates than FAI for average service lives of poles, despite ATCO Electric's contention that its poles are in a more benign environment, which would suggest a lower depreciation rate.

ATCO Electric replied stating that it did not file evidence on pole life, and that its pole life extension practices have been in place for many years. ATCO Electric indicated that the relevant information was reviewed and approved by the AUC in ATCO Electric's depreciation study filed with its 2011-2012 general tariff application. ATCO Electric submitted that a capital tracker proceeding is not the appropriate forum to review or change depreciation rates in the absence of a depreciation study. Accordingly, ATCO Electric submitted that the pole depreciation rates approved by the AUC continue to be appropriate for determining the cost impacts of this program.

The AUC agreed with ATCO Electric on this point, finding that in the absence of a new depreciation study, the AUC would not re-open the matter of depreciation rates for consideration in a capital tracker proceeding.

The Overhead Line Rebuilds, Replacement and Life Extension program was otherwise approved as filed with respect to Criteria 1.

ATCO Gas - Overhead Cost Allocation

The CCA took issue with ATCO Gas' request for capitalization of overhead costs, noting that ATCO Gas had provided "limited or no details to support the request".

The AUC agreed with the CCA, and found that ATCO Gas had not demonstrated that its capitalized overhead costs were prudent, as detailed information was not provided. Therefore, in the absence of such evidence supporting the overhead costs, the AUC declined to approve an increase in overhead costs, and directed ATCO Gas to include in its compliance filing amounts reflecting increases adjusted by the I-X mechanism applied to the 2012 total pool of overheads approved in Decision 2011-450.

The AUC determined that the scope, level and timing for all of ATCO Gas' applied for capital tracker projects were reasonable, with one minor exception. With respect to Steel Mains Replacement, the AUC did not expressly deny the cost estimates, but did deny capital tracker treatment to any carrying costs related to the advancement of steel replacements in 2011 that were planned for later years.

Criteria 3: Materiality Thresholds

With respect to the materiality of the proposed project groupings, the AUC noted that Criteria 3 imposes two tiers of materiality:

(a) A four basis point threshold, to be applied to each grouping of projects; and

(b) A forty basis point threshold for the aggregate revenue requirements proposed to be recovered from all proposed capital trackers.

FAI calculated that the materiality thresholds for each year applied for were as follows:

(a) A four basis point threshold of $330,000, and a 40 basis point threshold of $3.356 million for 2013;

(b) A four basis point threshold of $ 341,000, and a 40 basis point threshold of $33.409 million for 2014; and

(c) A four basis point threshold of $347,000, and a 40 basis point threshold of $3.464 million for 2015.

ATCO Electric calculated that the materiality thresholds for each year applied for were as follows:

(a) $224,000 and $2.238 million for 2013;

(b) $228,000 and $2.274 million for 2014; and

(c) $231,000 and $2.310 million for 2015.

ATCO Gas calculated that the materiality thresholds for each year applied for were as follows:

(a) $145,000 (north), $119,000 (south), and $1.448 million (north), $1.187 million (south) for 2013;

(b) $147,000 (north), $121,000 (south), and $1.471 million (north), $1.206 million (south) for 2014; and

(c) $149,000 (north), $123,000 (south), and $1.494 million (north), $1.225 million (south) for 2015.

The AUC made the following findings with respect to the materiality thresholds:

(a) For FAI, the AUC was not able to approve any specific amounts for material thresholds, arising from its directions to update the I-X Index Factor and billing determinants factors. The AUC therefore directed a compliance filing on this basis;

(b) For ATCO Electric and ATCO Gas, the AUC held that:

(i) Their 2013 values were reasonable, as they had been previously approved for 2013 in Decision 2013-435;

(ii) Their 2014 values were calculated correctly according to the approved escalation factors in the I-X mechanism; and

(iii) However, as the AUC determined that ATCO Electric and ATCO Gas had applied a placeholder for 2015, the AUC directed them to apply the 2015 I-X Index Factor of 1.49 percent approved in Decisions 2014-354 and 2014-363 in its compliance filing to this decision, and for all other capital tracker applications in 2015.

Due to the directed changes to the weighted average cost of capital rates, and to the various I factor and Q Factor indexes, the AUC determined that it could not determine whether ATCO Electric and ATCO Gas' applied for capital trackers met the materiality thresholds, as the underlying figures required a recalculation as part of their compliance filing, and reserved its findings on this matter accordingly.

<u>AUC Dispositions</u>

In summary, the AUC ordered compliance filings in accordance with the directions in their respective decisions by the following dates:

(a) April 14, 2015 for FAI;

(b) April 20, 2015 for ATCO Electric; and

(c) April 27, 2015 for ATCO Gas.

Various AUC NID and Facility Applications

Needs Identification Document - Facility Application

The AUC approved the following need applications and related facility applications upon finding that:

- The public consultation complies with *AUC Rule 007*;
- The noise impact assessment summary complies with *AUC Rule 012*;
- There was no evidence that the AESO need assessment is technically deficient;
- The facility proposed satisfies the need identified;
- Technical, siting and environmental aspects of the facilities comply with *AUC Rule 007*;
- Considering the social, economic and environmental impacts, the project is in the public interest; and
- The project is in accordance with any applicable regional plan.

Decision	Party	Application
3488-D01-2015	Alberta Electric System Operator	Amelia 108S Substation Upgrade Needs Identification Document
	AltaLink Management Ltd.	Amelia 108S Substation Upgrade Facility Application
3588-D01-2015	Alberta Electric System Operator	Thickwood Hills 240-kV Transmission Development Needs Identification Document
		[Facility Application to follow separately]
3575-D01-2015	Alberta Electric System Operator	ENMAX No. 11 Substation Alteration Needs Identification Document
	ENMAX Power Corporation	ENMAX No. 11 Substation Alteration Facilities Application

The AUC approved the following facility applications upon finding that:

- The public consultation complies with *AUC Rule 007*;
- The noise impact assessment summary will comply with *AUC Rule 012*;

- Technical, siting and environmental aspects of the facilities comply with *AUC Rule 007*; and
- Considering the social, economic and environmental impacts, the project is in the public interest.

Decision	Party	Application
3515-D01-2015	TERIC Power Ltd.	Sunrise Two-MW Natural Gas-fired Power Plant
3460-D01-2015	BowArk Energy Ltd.	Construction of 90-MW Power Plant
3374-D01-2015	AltaLink Management Ltd.	Medicine Hat Area 138-kilovolt Transmission Development Amendment to Mitigate Impacts near Railway Line
3379-D01-2015	Lafarge Canada Inc.	Lafarge Substations and Transmission Line
3547-D01-2015	AltaGas Holdings Inc.	AltaGas Kent Energy Plant

NATIONAL ENERGY BOARD

Additional Information Requirements Relating to Fish and Fish Habitat and Navigation for Notifications of Operations and Maintenance (O&M) Activities (February 19, 2015)
Additional Information Requirements - Fish - Fish Habitat – Navigation

The NEB released a letter in respect of information requirements for fish and fish habitat and navigation for notifications of Operations and Maintenance ("O&M") activities as a result of legislative changes from the *Jobs, Growth and Long-term Prosperity Act*, which amended certain provisions of the *National Energy Board Act*, and the *Canada Oil and Gas Operations Act*.

The NEB's additional information requirements are required for any operations or maintenance activities for which there will be:

(a) Ground disturbances using power-operated equipment within 30 meters of a wetland or water body (or the substrate of the same); or

(b) Crossings of a navigable water body while accessing a site, or if there will be ground disturbances or activities within or across a navigable body's wetted perimeter.

For a full listing of the additional information requirements, please consult Appendix I to the NEB's letter.

Court Challenges to National Energy Board or Governor in Council Decisions Database (March 23, 2015)
NEB Website – Court Challenges Database

The National Energy Board announced the release of a new database on its website to share information about challenges to the NEB's decisions and recommendations to the Governor in Council, as well as the status and outcome of such challenges.

The database contains the status of litigation, appeals and judicial reviews of NEB or Governor in Council decisions dating back to January 2014. The database is located here, on the NEB's website.

Letter to All NEB Regulated Companies: Emergency Procedures Manuals (March 26, 2015)
Emergency Procedures Manual

The National Energy Board informed all companies under its jurisdiction, via letter, that the Emergency Procedures Manuals ("EPMs") filed under subsection 32(2) of the *National Energy Board Onshore Pipeline Regulations*, and section 35 of the *National Energy Board Processing Plant Regulations*:

(a) Must be filed as one hard copy and electronic copy, as opposed to the current practice of sending three hard copies. The hard copy will be considered the official record by the NEB;

(b) Must be filed as a new and complete copy when filing an update to the EPMs, which incorporates all updates; and

(c) Must be filed by April 1 of each year for annual updates, or the company must provide and file a letter indicating that there are no changes to the EPMs.