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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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ALBERTA ENERGY REGULATOR

Amendments to Directive 060: Upstream Petroleum Industry Flaring Incinerating, and Venting (Bulletin 2015-30)
Bulletin – Directive 060

The AER announced changes to Directive 060: *Upstream Petroleum Industry Flaring, Incinerating, and Venting* ("*Directive 060*"), which came into effect on October 5, 2015. The AER noted the following revisions to *Directive 060*:

(a) Section 2 – The requirements for general conservation were amended to include condensate producing sites. (All applicable conditions and exceptions are detailed in section 2.6.) This change will reduce flaring and improve resource conservation;

(b) Sections 2, 3, 4, 5, and 6 – The requirements for notification of non-routine flaring, incineration, and venting were amended to include schools. (All applicable conditions and exceptions are detailed in sections 2.10, 3.8, 4.1, 4.2, 5.1, 5.4, and 6.4.) Schools will now be told of imminent flaring nearby. This will promote awareness within the school community;

(c) Section 7 – The requirements for modeling were amended to clarify the conditions requiring post-event dispersion modeling. (All applicable conditions and exceptions are detailed in section 7.12.5[7]); and

(d) Appendix 2 – The definition of schools was added and the definition of solution gas was revised to include gas from condensate production.

The revised edition of *Directive 060* can be accessed on the AER's website here.

Invitation for Feedback: Draft Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area (Bulletin 2015-31)
Bulletin – Invitation for Feedback – Emission Controls – Conservation

The AER sought public feedback until November 8, 2015, on a draft directive on requirements for addressing odours and emissions from heavy oil and bitumen operations in the Peace River area of Alberta, in response to concerns expressed by area residents. The draft directive was made pursuant to the recommendations made in Decision 2014 ABAER 005, and the AER's response to the recommendations made therein.

A copy of the draft directive can be found here.

The AER also noted that once the draft directive is finalized, subsequent changes to section 8.4 of Directive 056: *Energy Development Applications and Schedules*, and section 8.7.3 of Directive 060: *Upstream Petroleum Industry Flaring, Incinerating, and Venting* are anticipated to reference the new directive.

Request for Feedback: Draft Directive on Reservoir Containment Requirements in the Shallow Thermal Area of the Athabasca Oil Sands Area (Bulletin 2015-32)
Bulletin – Request for Feedback – Reservoir Containment

The AER announced that it is seeking public feedback on a draft directive pursuant to its technical review of the factors that affect reservoir containment of steam-assisted gravity drainage projects in shallow areas. The AER had previously announced the technical review in Bulletin 2014-03: *Regulatory Approach for Shallow Thermal In Situ Oil Sands Applications in the Wabiskaw-McMurray Deposit of the Athabasca Oil Sands Area*.

A copy of the draft directive can be found here. The AER will be accepting feedback on the draft directive until December 31, 2015.

Charges laid regarding October 2013 Obed Mountain Coal Mine Spill (News Release 2015-18)
News Release – Coal Mine Spill

The AER announced that charges under the *Environmental Protection and Enhancement Act* ("*EPEA*") and the *Public Lands Act* ("*PLA*") were laid against Sheritt International Corporation ("Sherritt") and Coal Valley Resources Inc. ("CVRI"), a subsidiary of Sherritt, from a wastewater containment pond spill that occurred in October, 2013. Six charges have been laid in total under the *EPEA* and *PLA*.

The AER noted that the waste water containment pond spill occurred at the Obed Mountain Coal Mine on October 13, 2013, located approximately 30 km east of Hinton, Alberta. The leak contaminated two tributaries of the Athabasca River.

A first appearance for Sherritt and CVRI is scheduled for January 20, 2016 in Hinton Provincial Court.

Charges laid regarding October 2013 Apache Zama City Pipeline Spill (News Release 2015-18)
News Release – Pipeline Spill

The AER announced that charges were laid under the *Environmental Protection and Enhancement Act* ("*EPEA*") and the *Public Lands Act* ("*PLA*") against Apache Canada Ltd. ("Apache") following an October 25, 2013 pipeline spill of approximately 1,800 m^3 of produced water impacting 3.8 hectares of land northwest of Zama City, Alberta.

The charges follow previous directions and orders from the AER to Apache, given on July 7, 2015, to take steps necessary to address issues with its internal pipeline management system.

A first appearance for Apache is scheduled for December 7, 2015 in Provincial Court in High Level, Alberta.

St. Albert Field Centre Relocating (Bulletin 2015-33)
Bulletin – Field Centre Relocation

The AER announced that the St. Albert Field Centre would be closing on Friday, November 6, 2015. Operations from the St. Albert Field Centre will be relocated to the Edmonton (Twin Atria) Office by November 9, 2015.

ALBERTA UTILITIES COMMISSION

Horse Creek Water Services Inc. Continuation of Existing Water Rates (Decision 20663-D01-2015)
Water Rates

Horse Creek Water Services Inc. ("Horse Creek") filed an application with the AUC requesting approval to continue charging its existing approved water rates, and to update its terms and conditions.

The rates previously in place were approved by the AUC in Decision 2011-061, which approved rates, as well as terms and conditions for Regional Water Services Ltd. ("RWSL"), to operate a water utility serving the residential development known as MonTerra on Cochrane Lakes in Cochrane, Alberta ("MonTerra").

Horse Creek purchased RWSL under a receivership order on August 6, 2014, and adopted RWSL's rates, as well as its terms and conditions. Horse Creek indicated to the AUC that it intended to file a rate application in 2016 to obtain higher water rates.

A number of stakeholders objected to the application, submitting that Horse Creek's existing water rates were much higher than those of comparable communities in Western Canada, and opposed Horse Creek's request to continue with its current rates.

The AUC determined that there was no persuasive factual basis upon which to conclude that the rates approved in Decision 2011-061, which expire on February 18, 2016, were no longer just and reasonable. The AUC also noted that the costs of a procedure to determine new rates (that would only remain applicable for a six-month period) would likely exceed any potential net cost savings. Therefore the AUC granted the approval for the continuation of the existing water rates until February 18, 2016.

The AUC also found that since Horse Creek had not yet filed its application for rates beyond February 18, 2016, it would be unlikely that the AUC would reach a final decision in relation to that application prior to February 18, 2016. Accordingly, the AUC determined that the continuation of the approved rates on an interim basis starting February 18, 2016 was warranted, conditional upon Horse Creek filing a general rate application on or before February 18, 2016.

The AUC determined that for the purposes of regulatory efficiency, it would consider Horse Creek's revised terms and conditions as part of Horse Creek's general rate application in 2016.

Accordingly, the AUC approved:

(a) The continuation of water rates as set out in Decision 2011-061 for the operation of the water utility serving MonTerra by Horse Creek;

(b) The approval of the water rates as set out in Decision 2011-061 for the operation of the water utility serving MonTerra by Horse Creek on an interim and refundable basis effective February 18, 2016; and

(c) The continuation of the terms and conditions of service approved in Decision 2011-061 for the operation of the water utility serving MonTerra by Horse Creek until otherwise directed by the AUC.

ATCO Electric Ltd. Application for Removal of CUL 307 from Isolated Generating Units Inventory (Decision 20634-D01-2015)
Removal of Generating Unit from Inventory - Isolated Generating Units and Customer Choice Regulation

ATCO Electric Ltd. ("ATCO") filed an application with the AUC for approval to dispose of mobile generating unit CUL 307 ("CUL 307") pursuant to section 13 of the *Isolated Generating Units and Customer Choice Regulation* ("*IGCCR*"), and strike CUL 307 from Part C of the Schedule to the *IGCCR*.

ATCO submitted that CUL 307 was no longer required to provide electricity service to an isolated community or industrial area, as the completion of the Steen River Capacity Upgrade project would render the CUL 307 surplus to ATCO. ATCO proposed that it would not sell CUL 307, but rather decommission and use CUL 307 for spare parts to support other mobile generating units. ATCO submitted that this would provide the most value to its customers.

The AUC noted that ATCO had initially planned to retire CUL 307 in 2012, but that ATCO later revised the retirement date to 2015 for the purpose of contingency response plans. The AUC also noted that CUL 307 would be surplus after the completion of the Steen River Capacity Upgrade project. Accordingly, the AUC determined that CUL 307 was no longer required to provide a reliable supply of electric energy to an isolated community or industrial area. The AUC therefore ordered that CUL 307 be struck from Part C of the Schedule to the *IGCCR* and that the costs associated with CUL 307 be removed from ATCO's tariffs effective December 31, 2015.

V N M Rural Electrification Association Limited Permission to Cease and Discontinue Operations; FortisAlberta Inc. Sale and Transfer of the V N M Rural Electrification Association Limited Distribution System (Decision 20733-D01-2015)
Cease and Discontinue Operations – Sale and Transfer of Distribution System

The V N M Rural Electrification Association Limited (the "VNM"), located northeast of Barrhead, Alberta, applied to the AUC pursuant to section 29(1) of the *Hydro and Electric Energy Act* ("*HEEA*") to cease and discontinue operations, as it planned to sell and transfer its assets pursuant to section 32 of the *HEEA.*

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

Standing Determination

Several rural electrification associations sought intervener status in the proceeding, citing legal and policy issues that were of a substantial and material interest to them (the "Intervening REAs").

The AUC denied standing to the Intervening REAs on the basis that Fortis' application did not have the potential to directly and adversely affect the rights asserted by the Intervening REAs in respect of their own rural electrification associations. The AUC noted that Fortis' service area would not expand into or overlap with any of the Intervening REAs' service areas. The AUC also determined that the Intervening REAs had no legal interest in the broader policy considerations relating to the purchase and sale of rural electrification associations to investor-owned utilities.

The AUC further denied standing on policy issues, holding that the legislature retained jurisdiction over the sale of rural electrification associations, as well as under what terms they may be sold.

Sale and Transfer of Assets

VNM submitted that its board of directors requested a formal offer from Fortis to purchase its electric distribution system. After receipt of the formal offer, VNM held a special general meeting on June 2, 2015, pursuant to section 23 of the *Rural Utilities Act*, to vote on the formal offer by Fortis. In total, 338 of the 626 registered members voted, with 97 percent of the votes cast in favour of the extraordinary resolution to sell and transfer the VNM assets to Fortis.

The resolutions of the VNM, for the sale and transfer of its assets to Fortis, were approved by the VNM board of directors on August 4, 2015.

In assessing whether the transfer was in the public interest, the AUC noted that the VNM assets were all located within Fortis' service area, and that Fortis represented that it would continue to provide service to the members served by the VNM. The AUC also noted that 97 percent of the voting members of the VNM voted to approve the transfer. In relying on the above submissions, the AUC held that the sale and transfer of the VNM assets to Fortis was in the public interest.

The AUC therefore directed that the VNM operations and related assets be transferred to Fortis.

The Asset Purchase Agreement between VNM and Fortis was based on a replacement cost new less depreciation ("RCN-D") formula previously approved by the AUC. VNM submitted that the resulting purchase price for the VNM assets was $16,008,000.

Having approved the application for the sale and transfer of the VNM assets, the AUC considered the prudence of the purchase price to be paid by Fortis for the VNM assets. The AUC accepted using the RCN-D formula and 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 for any adjustments to its rates due to the acquisition of the VNM. Accordingly, Fortis' rates remain unaffected by this decision.

Direct Energy Marketing Limited Review of AUC generic proceeding on the Regulated Rate Tariff – Cost Application 20892-A001 (Decision 20892-D01-2015)
Recovery of Costs – Review Proceeding - Dismissed

Direct Energy Marketing Limited ("DEML") submitted an application to the AUC seeking recovery of costs for legal and consulting fees related to DEML's request for review of Decision 2941-D01-2015: *Regulated Rate Tariff and Energy Price Setting Plans – Generic Proceeding: Part B – Final Decision*. The AUC dismissed DEML's request for a review in Decision 20416-D01-2015.

The AUC rejected the application on the basis that DEML was not entitled to any cost recovery pursuant to section 5.1 of Rule 022: *Rules on Intervener Costs in Utilities Rate Proceedings*, which states that a utility must bear its own costs when an application for review under Rule 016: *Review of Commission Decisions* is dismissed.

Draft amendments to AUC Rule 007 respecting environmental requirements and needs identification documents (Bulletin 2015-14)
Rule 007 - Amendments

The AUC announced proposed changes to Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* to reflect:

(a) Updates for environmental requirements, including environmental checklists for transmission line and substation projects;

(b) Streamlined application requirements for needs identification documents; and

(c) Elimination of applications for approval of certain isolated generating units.

The AUC noted that these requirements were most recently addressed in Bulletin 2014-03 and Bulletin 2015-12. The draft rule is available here, on the AUC website. Interested parties may provide final submissions by November 16, 2015.

EPCOR Distribution & Transmission Inc. 2015-2017 Transmission Facility Owner Tariff (Decision 3539-D01-2015)
Tariff – Transmission Facility Owner

EPCOR Distribution & Transmission Inc. ("EDTI") filed a general tariff application ("GTA") for its transmission facility owner ("TFO") function for the 2015, 2016 and 2017 test period. As part of its GTA, EDTI requested approval for the following forecast revenue requirements:

	2015	2016	2017
	($ million)		
Transmission tariffs	98.32	100.08	105.82
Increase from existing tariff	8.21	1.76	5.74
Annual increase	9%	2%	6%

EDTI requested a return on equity of 8.30 percent and common equity ratios of:

(a) 36.27 percent for 2015;

(b) 35.80 percent for 2016; and

(c) 36.23 percent for 2017.

The figures for 2016 and 2017 were applied for on a placeholder basis.

EDTI also applied for approval of:

(a) Its TFO terms and conditions of service ("T&Cs") under which EDTI provides transmission service to the AESO;

(b) The continued use of the following transmission reserve and deferral accounts:

  (i) Hearing cost reserve;

  (ii) Self-insurance reserve;

  (iii) AESO directed projects deferral account;

  (iv) Transmission property, business and linear taxes; and

  (v) Transmission short-term incentive deferral account; and

(c) Placeholder for capital structure and rate of return on equity for EDTI's transmission function, which were the subject of the AUC's 2013 Generic Cost of Capital proceeding.

EDTI described the changes in its forecast revenue requirements as being related primarily to capital additions in each of 2015, 2016 and 2017, including recovery of AESO direct projects deferral account balances for the Heartland project, and subsequent increases to operating costs. EDTI provided the following summary of its forecast capital expenditures and capital additions:

	2015 forecast	2016 forecast	2017 forecast
	($ million)		
Capital expenditures	48.6	70.1	47.8
Capital additions	437.	65.2	56.0

Three year test period

EDTI applied for its TFO tariff for a three year period, from 2015 through 2017 (the "Test Period"). EDTI submitted that the extended Test Period would increase regulatory efficiency and provide greater incentives for EDTI to implement cost saving measures during the Test Period. EDTI also noted that a three year period would coincide with the end of EDTI's performance based regulation term, which may reduce duplication and create further efficiencies.

The AUC agreed that the Test Period would create regulatory efficiencies and related cost savings as compared to a two year period. The AUC therefore approved the use of the Test Period, providing its findings on the accuracy of forecasting by EDTI elsewhere in its decision.

Nature of Best Available Information

The AUC held that information that becomes available after the filing of an application will be used in assessing the reasonableness and accuracy of the forecasts and methodology used by the applicant. The AUC confirmed that information that becomes available during a proceeding may be used for adjustments to revenue requirement or other forecasts. The AUC determined that it would consider the forecasts submitted in the application given the best information available. The AUC considered the reasonableness of each component of the forecasts elsewhere in its decision.

Operational Performance and Service Quality and Forecasting of "Bucket Projects"

EDTI did not propose any changes to its service levels for the Test Period. EDTI noted that it used two reliability indices to track its operating performance reliability: system average interruption duration index ("SAIDI"); and system average interruption frequency index ("SAIFI"). EDTI submitted that from 2009 to 2013, its SAIDI and SAIFI scores were 0.28 and 20.45 minutes, as compared with industry averages of 0.78 and 74.16 minutes. EDTI submitted that its high SAIDI and SAIFI scores were not indicative of a management choice to achieve an unreasonably high level of safety and reliability. EDTI submitted that its scores were reflective of an entirely urban transmission system, allowing EDTI to respond much more quickly and effectively than its comparators in the industry, who typically have a mix of urban and rural transmission systems.

Counsel for the AUC, in questioning EDTI, explored the concept of "bucket projects" which consist of a lifecycle program that is forecasted based on a three-year average of historical costs. EDTI noted that it could not forecast exactly what equipment would require replacements in a specific year given their variability from year to year.

The AUC held that the methodology of using historical actual costs to forecast capital projects could be a reasonable alternative to bottom up forecasting in certain circumstances. In noting the inconsistency of costs from year to year, the AUC found a three year average to be appropriate, as the length of the Test Period is expected to account for annual variability. Given the necessity for a compliance filing related to other matters, the AUC directed EDTI to update its three year average using 2012 to 2014 actuals in its compliance filing.

The AUC agreed that EDTI's elevated SAIFI and SAIDI performance levels were likely due to the urban nature of EDTI's service area. Therefore, the AUC held that the comparator group used by EDTI was not helpful, and directed EDTI to file a comparison of its SAIFI and SAIDI results as compared with other urban transmission utilities for it next GTA.

Outstanding AUC Directions

EDTI also addressed several outstanding directions made by the AUC in Decision 2014-269, which addressed EDTI's 2013- 2014 GTA. Directions 1 through 7, 9 through 12, 16, 19, 20, 29, 31 and 34 were, as the AUC found in Decision 3474-D01-2015, applicable to EDTI's future GTAs.

With respect to direction 20, the AUC directed EDTI, in future applications, to include costs, such as corporate services cost allocations to EDTI's portion of the Heartland Transmission line, and explain any material impact to corporate services costs allocated to Heartland through the AESO directed projects review process. EDTI explained that the resultant impacts would be provided in a future application as the direct assigned capital deferral accounts application had not yet been reviewed by the AUC.

The AUC accepted EDTI's explanation, and held that EDTI's compliance with direction 20 from Decision 2014-269 should be addressed in its next GTA.

With respect to direction 31, the AUC had directed EDTI to use the most recently approved return on equity of 8.75 percent and a 37 percent common equity capital structure for test years, and to be trued-up as necessary. After EDTI had submitted its application however, the AUC released Decision 2191-D01-2015, wherein it approved a return on equity of 8.3 percent and a capital structure of 36 percent common equity. As a result, EDTI amended its application at the direction of the AUC, and requested placeholder treatment for its return on equity and common equity ratios for 2016 and 2017. The AUC approved EDTI's amended return on equity figures, reflecting the AUC's findings in Decision 2191-D01-2015, and directed EDTI to true up its return on equity figures for 2016 and 2017 once a decision is issued for the next generic cost of capital proceeding.

Transmission Operating Costs

EDTI applied for operations and maintenance ("O&M") costs of $19.06 million in 2015, $18.64 million in 2016, and

$19.11 million in 2017. EDTI noted that its O&M costs in 2015 were 14.7 percent higher than its approved 2014 amounts, but only 2.3 percent higher than actual O&M costs for 2014. EDTI explained that the increase in 2015 operating costs was primarily due to contractor costs associated with a single year project implementing procedures related to supervisory control and data acquisition cyber security standards.

The bulk of the remaining changes in O&M costs, according to EDTI was attributable to a change in accounting for the Short Term Incentive ("STI") program. EDTI noted that the quantum of costs was not changing; only their treatment as capital, rather than operating costs.

EDTI forecast STI amounts of $0.96 million for 2015, $1.00 million for 2016 and $1.03 million for 2017. Since these costs would be capitalized however, EDTI submitted that the net effect on revenue requirement would be a decrease of $0.35 million in 2015, $0.33 million in 2016, and $0.31 million in 2017.

EDTI submitted that its incentive compensation structure is designed to attract and retain employees, and to improve EDTI's overall performance. Among the metrics captured by the STI program, EDTI noted that the STI program in 2014 tracked:

(a) Injury/illness frequency rate;

(b) Workplace observations completed;

(c) Variance of actual to base approved capital;

(d) Controllable operating costs per customer;

(e) SAIDI scores; and

(f) Customer service index.

The AUC accepted EDTI's STI program and metrics, holding that they would incent employees to provide excellent service and ultimately reduce costs. However, the AUC noted that incentive programs that are included in revenue requirement should be designed so that the resulting benefits accrue to customers.

As a result of its findings related to other O&M costs, such as corporate services, the AUC directed EDTI to refile its O&M expenses consistent with the directions made in the decision.

Labour Costs

EDTI applied for an increase in the number of full time equivalent ("FTE") positions in the Test Period as compared with its approved 161.7 FTEs in Decision 2014-269. EDTI submitted that the increase was required due to higher forecast workload from increased capital activity due to ongoing system growth, and due to the addition of an engineer-in-training program for succession planning. EDTI's requested FTE levels for the Test Period were as follows:

	2015 forecast	**2016 forecast**	**2017 forecast**
Operating FTEs	82.6	83.2	82.3
Capital FTEs	85.6	84.9	86.9
Total Forecast	168.2	168.1	169.2

EDTI arrived at its FTE numbers by adopting a new methodology, which led to a decrease of 4.1 FTEs for 2015 compared to its previous methodology.

The AUC held that the forecast capital FTEs were reasonable, and accepted EDTI's forecasts for the Test Period in this regard, noting that the capital activity and costs remained relatively constant. However, with respect to forecast operating FTEs, the AUC was not convinced that an increase was needed, noting that the actual figures of 71.3 operating FTEs in 2013 for a similarly sized transmission system was indicative that increased operating FTE levels were not required.

Additionally, the AUC directed EDTI to reduce the forecast operating FTEs for each of the years in the Test Period by 2.0 operating FTEs, and to apply an average cost per FTE of $130,000 for 2015 and $140,000 for 2016 and 2017, in its compliance filing.

With respect to vacancy rates for FTE positions, EDTI applied a zero percent vacancy rate for salaried employees. EDTI's actual two-year average of gross vacancies was 2.9 percent, consistent with the AUC's previous determination in Decision 2012-272 regarding negative vacancy factors.

The AUC held that due to the negative average vacancy rates for forecast FTEs, no vacancy factor was warranted for salaried FTEs during the Test Period. However, the AUC noted that EDTI had interpreted the AUC's findings in Decision 2012-272 in a manner other than it had intended. The AUC clarified that although it considers that vacancies do occur, EDTI's explanation that positive vacancy related variances were offset by higher staffing costs, overtime and use of contractors was not adequately supported. In light of the apparent ambiguity in its direction to apply gross vacancy levels, the AUC accepted EDTI's proposed zero vacancy rate. Accordingly, the AUC directed EDTI, in its next application, to disregard this direction.

Administration and General Expenses

EDTI applied for total administrative costs of $2.40 million for 2015, $3.00 million for 2016, and $3.60 million for 2017. EDTI explained that the majority of the change in costs was due to the capitalization of STI costs in 2014 actuals, which created much lower than forecast costs in 2014.

The AUC accepted EDTI's Administration and General expenses as filed, subject to any other directions in the decision.

Capital Overhead Rate Methodology

EDTI submitted that it allocated its indirect costs through its master overhead pool ("MOP") by dividing the capital overhead pool costs by total capital expenditures for EDTI transmission and distribution, consistent with the method used to calculate its 2012 to 2014 capital overhead rates. However, EDTI did not calculate a forecast for its distribution function, as it was under PBR.

The AUC determined that EDTI shared three basic common costs to be allocated between distribution and transmission:

(a) Common field operations costs incurred by distribution and charged to transmission through asset usage fees or allocators;

(b) MOP costs, allocated as the proportion of direct labour costs for administration and general labour costs; and

(c) Capital overhead costs, allocated a proportion of direct capital labour costs for capital expenditures on a forecast basis.

The AUC recognized that EDTI uses forecast allocators associated with services provided by EDTI to its affiliates and other common operations, in lieu of relying on historical information, noting that at the time of EDTI's reorganization it may not have had sufficient historical information to base its allocators between affiliates. Therefore, for the purpose of this decision, the AUC accepted EDTI's allocators as reasonable, but directed EDTI to provide historical information for its allocators of common costs for its next GTA.

Despite the lack of information available regarding EDTI's distribution function for MOP and capital overhead rates, the AUC found nonetheless that the MOP and capital overhead methodologies themselves were reasonable. Therefore the AUC was not convinced that a change to the methodologies was warranted. However, the AUC agreed with submissions made by the Consumers' Coalition of Alberta ("CCA") insofar as the absence of detailed information raised concerns about potential cross-subsidization between EDTI's transmission and distribution functions.

The AUC therefore directed EDTI to revise its forecast MOP and capital overhead rates to be consistent with those approved in Decision 2014-269 in its compliance filing, and to account for and explain any further adjustments due to the capitalization of STI costs.

Corporate Services Costs

EDTI requested approval of its corporate services costs as follows:

	2015 forecast ($) million	**2016 forecast ($) million**	**2017 forecast ($) million**
Transmission total	5.21	5.41	5.60
Less disallowed/ non-utility costs	(0.70)	(0.72)	(0.74)
Total corporate allocated to transmission	4.52	4.69	4.86

The AUC determined that EDTI's allocation methodologies for corporate cost allocations were reflective of the approach approved by the AUC in Decision 2014-269. Therefore, the AUC approved EDTI's corporate services costs as filed, with the exception of $0.08 million requested for Corporate Development costs. The AUC found that EDTI had failed to justify any cost reductions that may result from the Corporate Development department.

The CCA raised concerns respecting EDTI's rent costs in EPCOR Tower, noting that EDTI's allocable share of rent in EPCOR Tower had increased from 31.5% to 33.9% due to the fact that an affiliate had moved out of the space. The CCA therefore recommended that these costs be reduced to incentivize EDTI to exercise control over its rent costs. The CCA also submitted that EDTI's actual rent costs are at or above the high end of the market price of rental space.

The AUC held that a decision by other business units to transfer from the EPCOR Tower to elsewhere should not necessarily lead to an increase in corporate rent costs allocated to EDTI. The AUC held that EDTI had not justified why the costs associated with higher corporate rental costs arising from underutilization of space should be included in revenue requirement. Therefore, the AUC directed EDTI to remove the cost increases to EDTI due to the above noted vacant rental space during the Test Period.

<u>Allocations to the Heartland Project</u>

EDTI requested the following forecast revenue requirement related to the Heartland project:

	2015 ($) million	2016 ($) million	2017 ($) million
Return on equity	8.46	8.27	8.08
Return on debt	8.09	8.08	7.94
Depreciation	5.64	5.64	5.64
Operating costs	0.13	0.10	0.10
Linear taxes	0.19	0.20	0.21
Corporate cost allocations	0.68	0.70	0.73
Total	23.19	23.00	22.71

The AUC held that given its previous directions in Decision 2014-160, it would be inconsistent to deny the allocation of corporate service costs for the Heartland project simply due to its unique ownership structure. Therefore the AUC approved the Heartland project costs, subject to any adjustments from the AltaLink Direct Assign Capital Deferral Account Proceeding 3585.

<u>Transmission Deferral and Reserve Accounts</u>

EDTI requested a true-up of transmission deferral and reserve accounts that were in effect in 2014, and further requested the continuation of such accounts throughout the Test Period. EDTI requested the following amounts related to its deferral and reserve accounts:

	2014 actual ($) million	2015 forecast ($) million	2016 forecast ($) million	2017 forecast ($) million
Hearing cost reserve	0.36	0.05	0.24	0.24
Self-insurance reserve	(0.14)	-	-	-
Property, business & linear tax deferral account	0.55	(0.55)	-	-
AESO directed projects deferral account	(2.46)	3.58	-	-
Short-term incentive (STI) deferral	(0.06)	(0.05)	-	-
Total	(1.76)	3.03	0.24	0.24

The AUC accepted EDTI's reasons for continuing each of the five deferral accounts. However, the AUC noted that the AESO directed projects account included the Heartland project, which is the subject of a separate proceeding that the AUC noted was not likely to conclude in 2015. Therefore the AUC directed EDTI to remove the deferral account true-up for the Heartland project from its 2015 amounts, and reflect it instead in 2016.

<u>Rate Base</u>

EDTI requested approval of an opening 2015 net transmission rate base of $624.3 million.

After considering the reasonableness of the opening rate base by examining the actual capital expenditures and additions in 2013 and 2014, the AUC approved the opening rate base as filed.

<u>Cost Forecast Approach</u>

EDTI submitted that it applied a similar cost approach for all its lifecycle projects, based on:

(a) EDTI's cost estimates for engineering, materials, project management, construction, contractor supervision where required, testing and commissioning into service; and

(b) Where available, historical actual costing information for similar projects constructed in previous years.

EDTI further submitted that it applied a bottom-up approach to forecasting costs, based on the particular work required for each particular project. However, where a project's scope has yet to be defined, EDTI noted that it relied on three-year historical averages for similar projects.

In the course of forecasting costs, EDTI submitted that it took the following steps to minimize its costs:

(a) Utilization of competitive bid processes;

(b) Utilization of industry standard materials;

(c) Adopting existing designs and drawings from previous similar projects;

(d) Coordination of construction scheduling through its project management office; and

(e) Coordinating work schedules with other projects to minimize costs and maximize efficiencies.

For the purposes of asset replacement, EDTI submitted that it applies an asset health index tool to its existing assets to arrive at a risk index score for each asset. EDTI noted that it uses the risk index scores to create a priority sequence for addressing risks and replacing assets, which it updates annually. EDTI further submitted that a large number of its asset lifecycle programs were previously approved by the AUC.

The AUC did not approve EDTI's cost forecasting mechanism in general, but instead addressed the reasonableness of each project. However, the AUC cautioned EDTI against relying on prior AUC approvals as an indication of receiving the same treatment in future proceedings. The AUC held that while prior approvals do weigh in favour of continued approval, the AUC would still make its findings based on the evidentiary record before it in each instance.

<u>Overview of 2015-2017 Forecast Capital Expenditures and Additions</u>

EDTI applied for approval of the following forecast capital additions during the Test Period:

(a) $43.7 million in 2015;

(b) $65.2 million in 2016; and

(c) $56.0 million in 2017.

EDTI also applied for approval of the following forecast capital expenditures during the Test Period:

(a) $48.6 million in 2015;

(b) $70.0 million in 2016; and

(c) $47.8 million in 2017.

EDTI categorized its transmission capital additions into three main components, lifecycle projects, performance improvement projects, and AESO directed growth projects. EDTI noted that the majority of the performance improvement project cost in 2015 was due to the Lambton transformer capacity upgrade, representing $6 million or 15 percent of planned capital additions in 2015. With respect to lifecycle projects, EDTI submitted that these projects accounted for $23 million or 60 percent of planned capital additions in 2015:

(a) Protective relaying & control system replacements;

(b) Supervisory control and data acquisition upgrades;

(c) Communication system replacements and improvements;

(d) Medium voltage switchgear additions and replacements; and

(e) 500-kV air blast circuit breaker replacements.

EDTI noted that the majority of capital additions in 2016 were forecast to be attributable to AESO directed projects, such as the transmission reinforcement project known as the Garneau expansion, representing approximately $44 million or 67 percent of planned capital contributions in 2016.

In 2017, EDTI submitted that the majority of its planned capital additions were attributable to the following lifecycle replacement projects, representing $36 million or 64 percent of planned capital additions in 2017:

(a) Protective relay & control system replacements;

(b) Medium voltage switchgear additions; and

(c) Lifecycle replacement of 240-kV cable sections.

The AUC held that the bulk of the planned capital additions and expenditures were reasonable, however the AUC found several exceptions which it disallowed.

Notably, the AUC was concerned about the uncertainties and cost overruns associated with the south central transmission reinforcement project, which was an AESO directed project. The AUC noted that the AESO had yet to provide a Needs Identification Document application for the project, and further noted that there was uncertainty as to whether the project would be classified under the transmission or distribution function.

The AUC also disallowed forecast capital expenditures related to a 240-kV GIS substation project, which is an AESO directed project to improve transmission reliability in Edmonton. EDTI forecasted capital expenditures of $2.2 million, $0.6 million and $12.7 million in each of 2015, 2016 and 2017 respectively, but did not forecast any capital additions in the Test Period. EDTI also noted that a Needs Identification Document had yet to be filed by the AESO.

The AUC also disallowed proposed capital additions for the Rossdale and Victoria substation medium voltage switchgear addition projects. The AUC approved the capital expenditures for these medium voltage switchgear replacement projects, however, due to what the AUC foresaw as delays that would push the in service date (and hence the capitalization of these costs) past the end of 2017, the AUC held that these projects would not likely be capitalized within the Test Period.

The AUC disallowed the 240-kV lifecycle replacement project on the basis that the evidence on the record showed that good maintenance practices in concert with the average remaining service life of the 240-kV lines would render their replacement unnecessary during the Test Period. However, the AUC agreed that the replacement of the 240-kV sections would become necessary at a later date.

Accordingly, the AUC directed EDTI to remove the following costs from its revenue requirement in its compliance filing related to the following projects:

(a) The south central transmission reinforcement project;

(b) The 240-kV GIS substation project;

(c) The Rossdale and Victoria substations medium voltage switchgear replacement projects;

(d) The lifecycle replacement of 240-kV cable sections; and

(e) Other minor projects.

Return on Rate Base

EDTI's calculations of its return on mid-year transmission rate base, including return on debt and return on equity ("ROE") assumed an ROE of 8.75 percent and an equity ratio of 37 percent on a placeholder basis pending the 2013 Generic Cost of Capital decision. The AUC issued Decision 2191-D01-2015 approving the generic cost of capital for 2013 through 2015 with a return on common equity of 8.30 percent and a capital structure of 64 percent debt and 36 percent equity for EDTI throughout the same period. The AUC also approved the same capital structure for 2016 on an interim basis and each subsequent year unless otherwise directed by the AUC.

Accordingly, EDTI revised its application to reflect the AUC's findings in Decision 2191-D01-2015. EDTI noted that the impact of Decision 2191-D01-2015 resulted in a reduction to EDTI's forecast revenue requirement of $1.55 million for 2015, $1.57 million for 2016 and $1.55 million for 2017. EDTI calculated the return on rate base for the Test Period as follows:

Description	**2015 forecast**	**2016 forecast**	**2017 forecast**
Mid-year rate base ($ million)	657.16	686.80	722.86
Capital structure – equity (%)	36.27	35.80	36.23
Capital structure – debt (%)	63.73	64.20	63.77
Weighted average cost of capital (%)	6.18	6.22	6.25
Total return on mid-year rate base	40.63	42.73	45.15

The AUC held that EDTI's use of the most recently approved ROE of 8.30 percent for 2015 on a final basis and 2016 and 2017 on an interim basis was consistent with Decision 2191-D01-2015. The AUC directed EDTI to apply to true-up its ROE for 2016 and 2017 once a decision is issued in the next generic cost of capital proceeding.

The AUC held that EDTI did not reflect Decision 2191-D01-2015's approved debt and equity ratios of 64.0 and 36.0 percent for the Test Period. The AUC therefore directed EDTI, in its compliance filing, to recalculate its forecast transmission capital structure and average cost of capital and transmission return on rate base for the Test Period using the approved figures.

With respect to costs associated with the issuance of long-term debt, EDTI forecasted 2015 and 2016 long-term debt issues of $25 and $50 million respectively. An expert witness on behalf of EDTI determined its debt forecast costs using a four-step process:

(a) Consider one, two, and three year forward curve yield on 30-year Government of Canada bonds;

(b) Add a 60 basis points maturity premium in order to develop a forecast of the yields;

(c) Add a credit risk premium of 160 basis points to reflect the 'A' stand-alone credit rating of EDTI's transmission operations; and

(d) Add an allowance of five basis points for financing costs.

These four steps resulted in estimates of the cost of new long-term debt of 3.85 percent, 4.25 percent and 4.95 per cent for 2015, 2016 and 2017, respectively. EDTI submitted however that its actual cost of debt for 2015 was 4.17 percent, and therefore requested approval to recover those costs.

The CCA submitted that the range of volatility using the forecast debt cost approach favoured by EDTI is more than double that of alternative methodologies, and recommended that the AUC apply a forward curve rate methodology, as it argued those rates were closer to actual market rates.

The AUC held that, as the actual cost of debt for 2015 was known, the cost of debt issued at 4.17 percent was approved for inclusion in EDTI's 2015 revenue requirement. The AUC directed EDTI to reflect the actual 2015 debt rates in its compliance filing.

With respect to the debt forecasting methodology, the AUC held that the forecast based on the forward curve did not introduce any more risk than a forecast cost based on consensus forecasts. On this basis the AUC held that it preferred the forward curve methodology as it reflected actual market transactions, whereas the consensus forecasts were unrelated to market transactions. The AUC noted that the risk that the actual debt costs will differ from the forecast amount is simply an inherent risk faced by utilities in forecasting costs. The AUC therefore held that EDTI bearing the inherent risk of forecast debt cost rates may not actually materialize. Therefore, the AUC directed EDTI to implement the rates set out in the forward curve methodology. However, the AUC was equally clear in its decision that it was not directing EDTI to actually lock in its debt rates nor was it setting an actual cost of debt, but was setting a reasonable forecast debt cost for the purposes of EDTI's Test Period.

Accordingly, the AUC held that the 2016 forward curve cost of debt of 4.05 percent was a reasonable forecast cost of debt and directed EDTI to reflect this finding in its compliance filing.

Depreciation

EDTI proposed to continue its use of the direct life method of depreciation ("DLM"), which was first approved in Decision 2006-054, and was the subject of an AUC direction in Decision 2014-269. EDTI did not include a depreciation study, did not propose any changes to its methodology, and applied the previously approved depreciation rates to its forecast mid-year property, plant and equipment balances for the Test Period. EDTI's resulting depreciation expense calculations were as follows for the Test Period:

(a) 2015 – $22.27 million;

(b) 2016 - $23.84 million; and

(c) 2017 - $25.19 million.

The AUC held that it was satisfied with EDTI's calculations, and approved EDTI's depreciation expenses as filed. The AUC also noted EDTI's plans to undertake a depreciation study for its next tariff application. The AUC directed EDTI to conduct and file as part of its next application, research and conclusions respecting alternative methods of accounting for the cost of removal of retired assets under DLM beyond EDTI's current practice of capitalizing the cost of removal at the time a new asset is installed and placed into service.

The AUC also considered it necessary for EDTI to explore the effects of ISO Rule 502.2 functional specifications on the estimated useful service lives of EDTI's transmission lines and towers, and directed EDTI to file its findings in respect of the same in its next GTA.

Order

The AUC approved EDTI's 2015-2017 GTA application subject to the findings directions and conclusions in the decision. The AUC therefore ordered EDTI to submit a compliance filing on or before January 4, 2016 addressing the directions in the decision.

The City of Red Deer Compliance Filing to Decision 3599-D01-2015 (Decision 20802-D01-2015)
Compliance Filing – Transmission Facilities Owner – General Tariff Application

The City of Red Deer ("Red Deer") filed an application for confirmation of compliance with Decision 3599-D01-2015, which was issued in respect of Red Deer's 2015-2017 transmission facilities owner ("TFO") general tariff application ("GTA").

In Decision 3599-D01-2015, the AUC directed Red Deer to make several revisions and adjustments to its application, to be accompanied by a compliance filing. The AUC directed Red Deer as follows:

(a) Apply an overall inflationary increase of 3.75 percent for union employees, and apply a 0.25 percent step increase;

(b) Apply an inflationary increase of 3.5 percent for contractor escalation rates, without a step increase;

(c) Apply a vacancy rate of 1.0 percent to reflect vacancies;

(d) Apply a compounded inflationary escalator for property taxes of 4.0 percent through 2015-2017, including adjustments for the addition of substation 209S;

(e) Adjust Red Deer's recognition of contributions in its revenue requirement calculation so that contributions are recognized from the start of construction, and are accumulated as an offset to project expenditures, for the purpose of calculating its allowance for funds used during construction ("AFUDC"), and to make adjustments to its contribution amortization rate accordingly;

(f) Apply the most recent actual interest rate recorded by the Alberta Capital Finance Authority in forecasting its 15-year rolling average, being 2.235 percent for 2015-2017;

(g) Provide detailed costing for each component of its allocation methodology, originally approved in Decision 2005-149, as part of its next GTA;

(h) Refile its corporate costs based on its 2014 actual allocators and to provide a detailed explanation of any changes;

(i) Revise Red Deer's gross asset allocator to reflect directions to remove $2.679 million in 2016 capital additions and $13,000 related to land costs and other AFUDC costs held by AltaLink Management Ltd.;

(j) Provide updated timing of contributions for substation 209S and an updated AFUDC schedule for the impact of Decision 2191-D01-2015 (the generic cost of capital decision); and

(k) Update all schedules to reflect the new capital structure and return on equity amounts set by Decision 2191-D01-2015, regardless of the materiality.

Red Deer submitted a table indicating the overall impacts of its compliance with each AUC direction on its monthly tariff and revenue requirement as follows:

	2015 ($)	**2016 ($)**	**2017 ($)**
Applied-for revenue requirement	3,482,200	3,953,000	4,405,500
Total adjustment	(29,200)	(67,400)	(105,000)
Compliance filing revenue requirement	3,453,000	3,885,600	4,300,600
Monthly tariff	287,751	323,799	358,379

The AUC was satisfied that Red Deer had complied with all directions from Decision 3599-D01-2015, and approved Red Deer's GTA compliance filing as filed. The AUC therefore approved Red Deer's final TFO revenue requirements of $3,453,000 for 2015, $3,885,000 for 2016, and $4,300,600 for 2017.

The AUC noted that a reconciliation of Red Deer's interim rates and its final approved rates was in order, given that Decision 2014-305 approved the continuation of Red Deer's existing 2014 tariff at $323,715 per month on an interim basis for the first nine months of 2015. The AUC noted that Red Deer's final approved monthly tariff amount for 2015 was $287,751. Therefore, the AUC determined that Red Deer had collected excess tariff revenues of $35,964 per month, or $323,676 on an annual basis. The AUC directed Red Deer to remit to the Alberta Electric System Operator $323,676 to true up its 2015 interim TFO rate to the 2015 final approved TFO rate for costs collected between January 1, 2015 and September 30, 2015.

ATCO Gas and Pipelines Ltd. 2015-2016 Rider D Application (Decision 20737-D01-2015)
Rider D

ATCO Gas and Pipelines Ltd. ("ATCO Gas") applied for approval of its unaccounted-for gas ("UFG") rate rider ("Rider D") for 2015 and 2016. ATCO Gas requested approval to increase Rider D to 1.220 percent from 1.125 percent, effective November 1, 2015.

ATGO Gas submitted that UFG charges are recovered in-kind from all shippers on its distribution system using a three-year calendar average of physical measurement data to determine UFG. ATCO Gas noted the 2012, 2013, and 2014 UFG figures were 0.895 percent, 1.488 percent and 1.276 percent respectively.

In ATCO Gas' last UFG proceeding, the AUC directed ATCO Gas, in Decision 2014-290, to provide clear explanations of seasonal UFG differences, measurement corrections and reasons for UFG increases or decreases. The AUC also directed ATCO Gas to provide information on practices and procedures used to reduce UFG.

ATCO Gas submitted that the major cause of variable UFG from month to month is the limited estimating ability of its daily forecasting and settlement system ("DFSS") to allocate cycle billing reads, making UFG appear higher or lower from month to month. ATCO Gas submitted that the annual measurement period helps to reduce any month-to-month variability in readings.

ATCO Gas noted that the Rider D rate would increase by 8.4 percent from its last UFG application. ATCO Gas explained that a potential cause of the increase was likely due to temporary mixing of gas from two or more gas sources with differing heat values caused by the relocation and transition of gate stations as part of its urban pipeline replacement program.

The AUC accepted ATCO Gas' explanations of seasonal differences in UFG and measurement corrections, as well as the reasons for the increase in UFG. The AUC directed ATCO Gas to continue providing this information with its next UFG application for Rider D. The AUC therefore approved ATCO Gas' requested Rider D at 1.220 percent, effective November 1, 2015.

ENMAX Power Corporation Southwest Calgary Ring Road Transmission Line Relocation (Decision 20072-D01-2015)
Transmission Line Relocation

ENMAX Power Corporation ("ENMAX") filed applications with the AUC to alter and operate three 138-kilovolt (kV) transmission lines to accommodate construction of the Southwest Calgary ring road near Sarcee Trail and Glenmore Trail in Calgary, Alberta.

ENMAX owns and operates three transmission lines designated as 138-1.80L, 138-21.80L and 138-28.80L (the "Transmission Lines") which cross Sarcee Trail just north of the intersection with Glenmore Trail. ENMAX proposed the alterations due to a request from Alberta Transportation to move each of the lines to the east side of Sarcee Trail.

The AUC determined that the application by ENMAX sufficiently addressed the need identified by Alberta Transportation. The AUC also determined that a needs identification document was not required, given that the project was not for expansion or enhancement of the capability of the transmission system.

The AUC held that ENMAX's participant involvement program met the requirements of AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* and that no objections or concerns were raised. Accordingly, the AUC approved ENMAX's application to alter and operate the Transmission Lines as filed.

Market Surveillance Administrator allegations against TransAlta Corporation et al. Phase 2 – request for consent order (Decision 3110-D03-2015)
Consent Order – Disgorgement Payment – Monetary Penalty – Investigation and Hearing Costs

In this decision, the AUC considered whether it was in the public interest to approve a consent order, proposed by the Market Surveillance Administrator ("MSA") and TransAlta Corporation, TransAlta Energy Marketing Corp. and TransAlta Generation Partnership (collectively, "TransAlta"), to resolve the remaining issues in Proceeding 3110 and bring the proceeding to a binding and final conclusion.

TransAlta and the MSA proposed to settle the matter through a consent order which includes the following amounts to be paid by TransAlta:

(a) A disgorgement payment of $26,920,814.31;

(b) A monetary penalty of $25 million; and

(c) Payment of the MSA's investigation and hearing costs on a full indemnity basis in the amount of $4,327,542.29;

(the "Consent Order").

In phase 1 of Proceeding 3110, the AUC found that TransAlta contravened Section 6 of the *Electric Utilities*

Act and sections 2(h), 2(j) and 4 of the *Fair, Efficient and Open Competition Regulation* in late 2010 and early 2011.

The MSA filed its application for the approval of the Consent Order pursuant to section 54 of the *Alberta Utilities Commission Act* ("*AUCA*"), which allows the MSA and a person named in a notice to agree on the means to resolve all or part of a matter before the AUC, by applying to the AUC.

The AUC cautioned that it could only approve an agreement that was otherwise within its jurisdiction to approve. In Decision 3110-D02-2015, the AUC determined that it had authority to order the payment of an administrative penalty by the person named in a notice from the MSA, and that such payment was expressly payable to the General Revenue Fund pursuant to section 63 of the *AUCA*. The AUC also determined in Decision 3110-D02-2015 that it had the authority to order a person to pay costs associated with an investigation and hearing initiated by the MSA. As a consequence, the AUC also found that its authority did not otherwise include an ability to order restitution or other compensation in relation to a proceeding initiated by the MSA.

In determining which principles to apply in considering the consent order, the AUC took guidance from the principles developed by the Alberta Court of Appeal ("ABCA") applicable to joint submissions on sentencing in *R. v. G.W.C*, 2000 ABCA 333. In that decision, the ABCA determined that courts should not lightly interfere with a negotiated disposition that falls within an appropriate range for a given offence. Therefore, the negotiated disposition must only be rejected where it is contrary to the public interest and may bring the administration of justice into disrepute. The AUC noted that it took a similar approach in Proceeding 1533, which was also a settlement between the MSA and TransAlta under section 44 of the *AUCA*.

The AUC determined that it must not ask itself whether the Consent Order is the order that the AUC itself would have issued, but rather whether the Consent Order is fit and reasonable, and falls within a range of acceptable outcomes given the circumstances. The AUC therefore held that if it does not approve the Consent Order, it must either refer the Consent Order back to the parties or reject it outright.

The $26,920,814.31 Disgorgement Payment

With respect to the disgorgement payment of $26,920,814.31, the MSA submitted that the payment represented the economic benefits that TransAlta derived from its contraventions. The economic benefits did not reflect costs or losses incurred by TransAlta. Instead, it focused on hours in which pool prices were higher as a result of outage timing. The MSA noted that it did not include any mitigating price impacts that would have occurred during the alternative outage timing.

The MSA noted that the estimates of economic benefits were derived from the expert information prepared for both the MSA and for TransAlta in Phase 1 of Proceeding 3110. The MSA submitted that the magnitude of economic benefit was very similar regardless of which estimates were used.

The AUC referred to section 7 of AUC Rule 013: *Rules on Criteria Relating to the Imposition of Administrative Penalties* ("*Rule 13*"). *Rule 13* provides that where a person derives an economic benefit as a result of a contravention, the AUC must order that person to disgorge the economic benefit in an amount determined by the AUC to nullify any gains acquired through misconduct.

The AUC was satisfied that TransAlta derived economic benefits as a result of its contraventions and that the public interest requires that any economic benefit be recovered. The AUC found that the MSA's estimated benefits derived by TransAlta as a result of its contraventions without setting off any related costs or losses was consistent with the intent of section 63(2) of the *AUCA* by including it as part of the administrative penalty.

The $25 million Monetary Penalty

The MSA submitted that the $25 million figure was a global award taking into account:

(a) TransAlta's contraventions of the legislation;

(b) The interrelated nature of the contraventions;

(c) The number of days upon which the outages and trading took place; and

(d) That the contraventions arguably extended beyond the days upon which the outages were taken.

The AUC, in considering the magnitude of the $25 million monetary penalty, took guidance from section 4 *Rule 13* in providing its findings on the appropriateness of the Consent Order.

The AUC noted that in Decision 3110-D01-2015, it found that TransAlta engaged in conduct that did not support a fair, efficient and openly competitive electricity market when it restricted or prevented its competitors from providing competitive responses, manipulated market prices away from a competitive market outcome and allowed its employee to use non-public outage records to trade in the electricity market. The AUC in this decision found that the contraventions were very serious, having regard to the following factors:

(a) The contraventions resulted in significant and widespread harm to customers by negatively impacting the pool price;

(b) The contraventions resulted in significant financial gains for TransAlta;

(c) The outage contraventions were premised on manipulation, and were part of a scheme that was systematic and persistent;

(d) The portfolio bidding strategy was approved by TransAlta's senior management at the time;

(e) TransAlta's vice president of trading and asset optimization, and TransAlta's vice president of commercial operations and development permitted an employee to trade when they knew or ought to have known that the employee had non-public outage records;

(f) The portfolio bidding strategy was pursued between November 2010 and February 2011;

(g) The outage contraventions were brought about by a complaint from a market participant, and the trading contraventions were discovered by the MSA in the course of its investigation; and

(h) TransAlta had previously breached section 2(h) of the *Fair, Efficient and Open Competition Regulation* in November 2010 by impeding import transactions.

Regarding matters of cooperation, the AUC observed that Proceeding 3110 entailed extensive disclosure from TransAlta. However, the AUC noted that TransAlta failed to provide some material and relevant documents, including the internal memorandum describing the portfolio bidding strategy, to the MSA, until late 2013. The AUC also noted that TransAlta either deleted or lost some hard drives belonging to relevant persons after the MSA initiated its investigation.

The AUC determined that, while one purpose of administrative penalties is to remove the profit from the offences, there was a legitimate purpose to providing fines in excess of the profit, lest the penalties become a simple 'licencing fee' for the offences. On the other hand, the AUC was careful to note that the monetary penalty could not be so large as to be considered penal in nature.

The AUC found that the proposed penalty approached the maximum penalty available under section 63(2) of the *AUCA*, given the duration of TransAlta's contraventions. However, having regard to the factors set out above, the AUC determined that the $25 million penalty was fit and reasonable, falling within a range of acceptable outcomes.

<u>The MSA's Investigation and Hearing Costs</u>

The Consent Order included the MSA's investigation and hearing costs in the amount of $4,327,542.97. The MSA submitted that this recovery was on a full indemnity basis, as opposed to being recovered on the AUC's *Scale of Costs* in Rule 15: *Rules on Costs of Investigations, Hearings, or Other Proceedings Related to Contraventions* ("*Rule 15*"). The MSA submitted that recovery of costs on a full indemnity basis served the purpose of providing an element of deterrence to would-be transgressors, given the lengthy and costly investigation into the matter by the MSA.

The AUC was satisfied that the inclusion of the MSA's investigation and hearing costs in the Consent Order was reasonable and in the public interest, given the complexity, length and novelty of the issues litigated. The AUC also held that *Rule 15* authorized it to grant costs in excess of the Scale of Costs and accordingly held that the proposed costs in the Consent Order were reasonable.

<u>Other terms</u>

The MSA submitted that the Consent Order included provisions that TransAlta must pay the following amounts within the following time frames:

(a) The disgorgement amount must be paid, along with the MSA's hearing and investigation costs within 30 days of the date upon which the consent order is approved; and

(b) The monetary penalty must be paid within 395 days of the date upon which the consent order is approved, plus any applicable interest pursuant to the *Judgment Interest Act*.

TransAlta submitted that it required additional time to pay the monetary penalty given the magnitude of the penalty, submitting that a single payment could lead to a downgrade of its debt instruments by credit rating agencies, which would in turn have a deleterious effect on TransAlta's operations.

The AUC held that the terms and conditions described in the Consent Order were appropriate, and determined that any risks associated with a staged payment had been appropriately addressed by the parties by requiring the provision of an irrevocable letter of credit until such time as the monetary penalty is paid.

Conclusion

The AUC found that the approval of the Consent Order was in the public interest. The AUC also held that the payment of the MSA's investigation and hearing costs on a full indemnity basis was warranted in the circumstances. While the AUC considered the magnitude of the penalty at approximately $56 million to be considerable, it also held that it was a proportional response to the seriousness of TransAlta's contraventions of the statutory scheme. The AUC determined that the approval of the Consent Order would promote regulatory compliance and achieve effective general and specific deterrence without being punitive.

EPCOR Energy Alberta GP Inc. 2016 Interim Regulated Rate Tariff (Decision 20676-D01-2015)
Interim Regulated Rate Tariff

EPCOR Energy Alberta GP Inc. ("EEA") applied for approval of its 2016 interim non-energy regulated rate tariff ("RRT") effective January 1, 2016. EEA's application was applicable to its 2016 RRT service provided to the EPCOR Distribution & Transmission Inc. ("EDTI") and FortisAlberta Inc. ("FAI") service areas. EEA submitted that, as there was insufficient time for the AUC to consider EEA's 2016-2017 RRT application in Proceeding 20633 and approve any such RRT on a final basis before January 1, 2016, an interim tariff was in order.

EEA requested approval of the following items as part of its application:

(a) The 2016 forecast non-energy charge for each EEA customer class, as applied-for in EEA's 2016-2017 RRT application in Proceeding 20633;

(b) EEA's hearing cost reserve and short-term incentive deferral accounts, as applied-for in Proceeding 20633;

(c) The price schedules, including miscellaneous fees, attached as schedules A-1 (EDTI service area) and A-2 (FAI service area) to its application;

(d) EEA's RRT terms and conditions of service, approved in Decision 3574-D01-2015, attached as Schedule B-1 to its application; and

(e) That any interim tariff remain in effect until the earlier of the AUC's approval of EEA's application in Proceeding 20633 and EEA's implementation of the same, or the AUC's approval for revisions to the applied for interim RRT.

EEA further submitted that the application resulted in just and reasonable tolls and was in the public interest. EEA's proposed 2016 interim non-energy charges reflect the lower costs applied for by EEA in Proceeding 20633 as compared with EEA's current 2015 RRT non-energy charges. EEA also submitted that the implementation of the 2016 interim tariff would result in a smaller true-up once 2016 final rates are in effect as compared to the continued collection of 2015 non-energy charges on an interim basis.

The AUC noted that EEA was requesting significant changes to its current RRT non-energy charges in Proceeding 20633, noting that non-energy charges were slated to drop for all customer classes by at least 20 percent (with the exception of security lights.) The AUC further determined that customers would not be prejudiced by an approval of interim rates, given their refundable nature. Accordingly, the AUC approved EEA's non-energy RRT charges on an interim refundable basis.

NATIONAL ENERGY BOARD

Steelhead LNG (A-E) Inc. Applications for Licence to Export Natural Gas, in the form of Liquefied Natural Gas (October 1, 2015)
Licence to Export LNG

Steelhead LNG (A) Inc., Steelhead LNG (B) Inc., Steelhead LNG (C) Inc., Steelhead LNG (D) Inc., Steelhead LNG (E) Inc. (collectively "Steelhead") each applied to the NEB pursuant to section 117 of the *National Energy Board Act* ("*NEB Act*") for licences to export gas in the form of liquefied natural gas ("LNG").

Each Steelhead applicant sought export licences on identical terms, with the exception of the export point. The common terms between each Steelhead applicant were as follows:

(a) A 25-year Licence, starting on the date of first export;

(b) A maximum annual export quantity of 6.9 million metric tonnes (MMt) or 356.5 billion cubic feet (Bcf) of LNG, including a 15% annual tolerance;

(c) A maximum term export quantity of 173 MMt (8,920 Bcf) over the term of the Licence; and

(d) An early expiration clause, whereby the Licence will expire ten years from the date of the approval of the Governor in Council if export has not commenced on or before that date.

The export points of each of the Steelhead applicants are as follows:

(a) Steelhead LNG (A) Inc. requested an export point at the outlet of the loading arm of the proposed natural gas liquefaction terminals which are anticipated to be located near the village of Mill Bay, British Columbia, Canada; and

(b) Steelhead LNG (B) Inc. and Steelhead LNG (C) Inc., Steelhead LNG (D) Inc., and Steelhead LNG (E) Inc. requested an export point at the outlet of the loading arm of the proposed natural gas liquefaction terminals which are anticipated to be located in the vicinity of Sarita Bay near the Trevor Channel, British Columbia, Canada.

In support of the applications, Steelhead submitted the following two studies to demonstrate that the quantity of gas to be exported does not exceed the surplus remaining after the due allowance has been made for the reasonable foreseeable requirements for use in Canada:

(a) Supply and Demand Market Assessments – prepared by Navigant Consulting, Inc. ("Navigant Report"); and

(b) Export Impact Assessments – prepared by Gordon Pickering ("Pickering Report").

The Navigant Report stated that Canadian and North American markets had ample and stable supplies. The Navigant Report also concluded that the abundant volume of natural gas would help support an assessment that the quantities of natural gas to be exported by Steelhead would not threaten the ability of the market to meet Canadian requirements for natural gas. The Navigant Report conducted a sensitivity test by increasing forecasted demand by 20 percent, and noted that the incremental increases were not material to its conclusions in respect of the surplus of gas available.

The Pickering Report noted further that recent changes in the integrated gas industry from shale gas development would make it highly unlikely that the export applications would cause any difficulty for Canadians to satisfy their own domestic natural gas demands.

The NEB decided to issue an export licence to each Steelhead applicant at their respective export points, subject to the approval of the Governor in Council and subject to the terms and conditions as requested by each of the Steelhead applicants. The NEB held that it was satisfied that Steelhead had demonstrated that the gas resource base in Canada could reasonably accommodate foreseeable Canadian demand, including the LNG exports proposed by the Steelhead applicants.

As part of the conditions of each 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.

National Energy Board opens 25-day Comment Period on Update to the National Energy Board's Damage Prevention Regulatory Framework (October 20, 2015)
Damage Prevention Regulatory Framework

As a result of the *Pipeline Safety Act* (Bill C-46) receiving Royal Assent on June 18, 2015, which amends the National *Energy Board Act* effective June 18, 2016, the NEB noted that changes will be required to its pipeline Damage Prevention Regulations ("DPR") within that same timeframe.

The Pipeline *Safety Act* authorized the NEB to make regulations based on a positive requirement approach, rather than an exemption based approach.

The NEB summarized three main areas where the DPR will be updated:

(a) Modernizing regulatory language. The NEB noted that the *National Energy Board Pipeline Crossings Regulations, Part I* section 4 creates an exemption based structure where 'leave of the Board' is not required for specified activities. The NEB noted that the intent of modernizing the regulatory language would impose positive obligations on the party wanting to undertake the activity in question;

(b) Consequential amendments to reflect the legislative amendments to the *National Energy Board Act*, including:

   (i) Replacing the term 'excavation' with the broader term 'ground disturbance' throughout;

   (ii) Defining a 'prescribed area' in which unauthorized ground disturbances are prohibited;

   (iii) Identifying new measures for the safe construction of facilities on, across, along or under a pipeline, in a prescribed area; and

   (iv) Identifying measures in order for a vehicle or other mobile equipment to safely cross a pipeline; and

(c) Amendments to the regulations to reflect the results of the NEB's last public consultations, including:

   (i) Adding a damage prevention program requirement to the *Onshore Pipeline Regulations*;

   (ii) Adding a requirement for third parties to initiate a locate request with their local one-call centre prior to ground disturbances;

   (iii) Adding a requirement for NEB-regulated pipeline companies to be members of one-call centres where they operate a pipeline; and

   (iv) Adding the intent of the NEB's Exemption Order MO-21-2010 (Low Risk Crossings by Agricultural Vehicles) into the regulations.

The NEB noted that the comment period will be open until November 13, 2015. Comments may be provided by email, fax, or mail to the NEB. The NEB's letter to parties providing notice of the comment period can be found here.

Changes to NEB electronic filing system
Announcement - Electronic Filing System

The NEB announced that, effective October 21, 2015, the NEB's electronic filing system will be changed to automate the exhibit numbering process when filing documents.

Period for Applications to Participate in NOVA Gas Transmission Ltd's Towerbirch Expansion Project (October 21, 2015)
Notice – Applications to Participate

The NEB announced that parties wishing to participate in NOVA Gas Transmission Ltd.'s Towerbirch Expansion Project application proceeding must apply through the Application to Participate (ATP) process between November 2 through 27, 2015.

Parties can apply to participate by clicking here.