ISSUE:
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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 John Gormley at John.Gormley@RLChambers.ca.

IN THIS ISSUE:

SUPREME COURT OF CANADA

Orphan Well Assn. v. Grant Thornton Ltd.
Leave Application – Leave Granted

The Supreme Court of Canada granted the Orphan Well Association and Alberta Energy Regulator leave to appeal the decision of the Alberta Court of Appeal in *Orphan Well Assn. v. Grant Thornton Ltd.*, 2017 ABCA 124. The Supreme Court of Canada, as is its normal practice, did not provide reasons for its decision to allow leave to appeal.

The decision under appeal concerned whether a trustee and receiver in bankruptcy can disclaim certain unprofitable well assets, pursuant to the federally enacted *Bankruptcy and Insolvency Act*, without having to fulfill its obligations in relation to abandonment, reclamation, and remediation of licensed properties under the provincially enacted *Oil and Gas Conservation Act* and the *Pipeline Act*.

ALBERTA ENERGY REGULATOR

Declaration naming Richard J. Nixon and Dale Brand under section 106 of the Oil and Gas Conservation Act
Declaration under Section 106 of the Oil and Gas Conservation Act

On October 30, 2017, the AER notified Richard J. Nixon and Dale Brand of the AER's intention to name them in a declaration pursuant to section 106 of the Oil and Gas Conservation Act ("*OGCA*").

In this decision, the AER issued declaration under section 106(1) of the *OGCA* naming Richard J. Nixon and Dale Brand as persons in direct or indirect control of Midlake Oil & Gas Limited ("Midlake"), a company that contravened or failed to comply with orders of the AER and had a debt to the AER.

Declaration under Section 106 of the *OGCA*

The AER explained that *OGCA* section 106 applies where the AER considers it in the public interest to make a declaration naming one or more directors, officers, agents, or other persons who, in the AER's opinion, were directly or indirectly in control of a licensee, approval holder, or working interest participant that has (i) contravened or failed to comply with an order of the AER; or (ii) has an outstanding debt to the AER, or to the AER to the account of the orphan fund, in respect of suspension, abandonment, or reclamation costs.

Background

Mr. Nixon had acted as a director, president, chief executive officer and shareholder of Midlake, and Mr. Brand had acted as the company's executive vice-president.

On November 25, 2015, Mr. Nixon notified the AER on behalf of Midlake that the company had deemed all of its assets to be under the sole care and custody of the AER and that the company was effectively "walking away" from its licensed properties.

AER Findings

Midlake contraventions of AER orders and outstanding debts

The AER found that Midlake subsequently failed to:

(a) comply with an order to pay a security deposit;

(b) comply with a closure and abandonment order; and

(c) pay the AER its 2016 Administrative Fees Levy in the amount of $56,220.49 and money owing to (i) the Orphan Fund for rentals associated with its public lands dispositions; and (ii) the Orphan Well Association for work completed by the OWA in respect of its licensed properties, totalling $ 89,000.

Person in control

The AER found that:

(a) Mr. Nixon was a director or person directly or indirectly in control of the company for the purposes of section 106 of the *OGCA*; and

(b) Mr. Brand was a person in direct or indirect control of the company for the purposes of section 106 of the *OGCA*.

Section 106 declaration

The AER confirmed its findings from previous decisions that:

(a) the purpose of a section 106 declaration is to prevent a licensee or person in control from continuing to breach requirements or incur new breaches or debts, thereby safeguarding the public interest; and

(b) continued confidence in the regulatory system is best assured when licensees comply with AER requirements.

In this case, the AER found:

- Midlake's decision to "walk away" from its licensed properties and the company's ongoing failure to comply showed a blatant disregard for AER requirements.
- Midlake's actions undermined the regulatory system and posed an unacceptable risk to public safety and the environment.

The AER concluded that issuance of a declaration was necessary to deter future noncompliance and uphold the credibility of the regulatory system and AER enforcement processes.

ALBERTA UTILITIES COMMISSION

AltaGas Utilities Inc. – 2016 Capital Tracker True-Up Application (Decision 22710-D01-2017)
PBR Plan – Capital Tracker True-up – K factor adjustment

In this decision, the AUC considered AltaGas Utilities Inc.'s ("AltaGas") 2016 capital tracker true-up application (the "Application").

For the reasons summarized further below, in this decision, the Commission made the following determinations:

- because three projects, Drumheller Phase 6 (town), Settler Area 1 (town), and Erskine (rural) were not previously determined by the AUC to be needed, the AUC assessed these projects and found all three to be needed.
- the actual scope, level, timing and actual costs of each of the projects or programs included in the 2016 true-up were prudently incurred and satisfied the project assessment requirement of Criterion 1.
- the capital tracker projects or programs included in the 2016 true-up continued to meet the requirements of the accounting test under Criterion 1.
- there was no need to reassess the project or program requirements against Criterion 2, unless the driver for the project or program had changed.
- the projects or programs included in the 2016 true-up satisfied the materiality requirement under Criterion 3.
- with one exception (discussed below), the AUC found that AltaGas complied with previous Commission directions.

<u>Overview of PBR Capital Tracker Mechanism</u>

The Performance Based Regulation ("PBR") framework approved in AUC Decision 2012-237 for 2013-2017 PBR plans provides a formula mechanism for the annual adjustment of rates over a five-year term. In general, the companies' rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation ("I Factor") relevant to the prices of inputs less an offset ("X Factor") to reflect productivity improvements that the companies can be expected to achieve during the PBR plan period. The resultant I-X mechanism breaks the linkages of a utility's revenues and costs under a traditional cost-of-service model. The PBR framework allows a company to manage its business with the revenues provided for in the indexing mechanism and is intended to create efficiency incentives similar to those in competitive markets.

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

The AUC approved a rate adjustment mechanism to fund certain capital-related costs, referred to as the capital tracker. The capital tracker provides a supplemental funding mechanism for approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate setting formula.

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

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

(b) ordinarily, the project must be for replacement of existing capital assets or the project must be required by an external party ("Criterion 2"); and

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

Criterion 1: Project Assessment and Accounting Test

Criterion 1 requires a two-stage assessment of each project or program for which capital tracker treatment is requested.

At the first stage (project assessment), an applicant must demonstrate that:

(a) the project is required to provide utility service at adequate levels; and, if so,

(b) the scope, level and timing of the project are prudent, and the forecast or actual costs of the project are reasonable.

At the second stage, an applicant must demonstrate the absence of double-counting (the "Accounting Test"). The Accounting Test requires an applicant to demonstrate that the associated revenue provided by the PBR formula will be insufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the program or project in question.

Criterion 2

With respect to Criterion 2, a growth-related project will generally qualify where an applicant demonstrates that customer contributions and incremental revenues are insufficient to offset the project's cost.

Criterion 3: Materiality Test

To assess whether a proposed capital tracker has a material effect on a company's finances, an applicant must satisfy the two-part Criterion 3 materiality threshold, namely, that:

(a) each individual project affects the revenue requirement by four basis points; and

(b) on an aggregate level, all proposed capital trackers must have a total impact on the revenue requirement of 40 basis points.

<u>AUC Review Process for 2016 Capital Tracker True-up</u>

In this decision, the AUC set out its approach for reviewing 2016 capital tracker true-up applications:

- For capital projects or programs not considered in prior capital tracker decisions, the AUC would assess all three criteria.
- For projects or programs for which the need was previously confirmed under the project assessment component of Criterion 1, the AUC would not reassess the need in the absence of evidence that the project or program was no longer required. However, the AUC would assess the scope, level and timing of each project or program for prudence, and whether the actual costs of the project or program were prudently incurred, as required by the second part of the project assessment under Criterion 1.
- For programs or projects for which the AUC undertook and approved the assessment against the Criterion 2 requirements in prior capital tracker decisions, it would not reassess this unless the driver for the project or program had changed.
- The AUC would conduct an assessment of the 2016 capital tracker projects and programs with respect to the Accounting Test under Criterion 1 and materiality test under Criterion 3.
- To the extent the AUC had previously approved the grouping of projects for capital tracker purposes, it would not re-evaluate these groupings in this decision.

<u>programs or projects for which AltaGas has sought a capital tracker true-up in 2016 on an actual basis</u>

The AUC noted it previously approved capital tracker treatment for the three programs: Pipeline Replacement, Station Refurbishment and Gas Supply.

These programs included in the 2016 capital tracker true-up and the variance from the approved forecast, resulting in a K factor true-up for 2016, are set out in the table below.

Table: AltaGas Applied-for 2016 K factor true-up adjustments

Program name	2016 approved forecast K factor	2016 actual K factor	K factor true-up
	($)		
Pipeline Replacement	4,583,929	4,126,045	(457,884)
Station Refurbishment	839,793	818,954	(20,839)
Gas Supply	372,931	338,395	(34,536)
2016 K factor total	5,796,653	5,283,394	(513,259)

<u>Capital Tracker Programs and Grouping of Projects</u>

The AUC set out the three capital tracker programs for which it had previously approved the need for as part of the project assessment under Criterion 1, namely:

(a) the Pipeline Replacement Program: a multi-year program for the replacement of certain types of pipe;

(b) the Station Refurbishment Program: a multi-year program for the replacement or refurbishment of three station types: purchase meter stations ("PMS"), town border stations ("TBS") and post-regulator stations ("PRS"); and

(c) the Gas Supply Program: a multi-year program to ensure safe, continuous gas supply to customers.

Given that the groupings in the Application were the same as those previously approved, the AUC found that there was no need to re-evaluate those groupings in this decision.

<u>Project Assessment under Criterion 1</u>

Under the project assessment requirements of Criterion 1, the AUC assessed whether the actual scope, level, timing and costs of the project were prudent.

Considering the individual projects within the Pipeline Replacement Program

The Pipeline Replacement Program ("PRP") consisted of projects for the replacement of three types of pipes:

(a) pre-1957 steel pipe;

(b) polyvinylchloride ("PVC") pipe; and

(c) non-certified and interim-certified polyethylene (PE) ("non-certified PE"),

(collectively, the "PRP Projects").

The AUC previously approved, for capital tracker treatment purposes, the need on a forecast basis for each of the pre-1957 steel, PVC and Non-Certified PE PRP Projects (the "Approved PRP Projects"), except for Drumheller Phase 6 (town), Settler Area 1 (town), and Erskine (rural).

Given that the AUC previously evaluated the Approved PRP Projects against the project assessment component of Criterion 1, AltaGas was not required to demonstrate that these projects were needed in 2016 if there was no evidence on the record to show otherwise.

In this case, the AUC found that:

(a) there was no evidence on the record to indicate that any of the PRP Projects were not required in 2016;

(b) with respect to the scope, level and timing of each of the Approved PRP Projects carried out in 2016, the AUC found that the actual capital additions associated with each of the projects and were generally consistent with the scope, level and timing of the work outlined in the previously approved business case;

(c) the actual scope, level, timing and costs of the work undertaken in 2016 were prudent; and

(d) accordingly, each of the Approved PRP Projects satisfied the project assessment requirement of Criterion 1 for 2016.

As the AUC previously determined in Decision 2012-237 and in Decision 2013-435, in this decision the AUC confirmed that a company may undertake a capital investment project prior to applying for capital tracker treatment. This was the case for the two pre-1957 steel pipe replacement projects (Drumheller Phase 6 (town) and Settler Area 1 (town)) and the one Non-Certified PE pipe replacement project (Erskine (rural)) (the "2016 PRP Projects").

For these projects, which AltaGas had undertaken in 2016 without first obtaining AUC approval for capital tracker treatment thereof, the AUC found that the 2016 PRP Projects were needed and that it was prudent for AltaGas to undertake them.

With respect to the scope, level and timing of the work associated with the three 2016 PRP Projects, the AUC found that:

(a) the information provided by AltaGas regarding each project was generally consistent with the scope, level and timing of the work outlined in the business case approved for the PRP; and

(b) the costs of the PRP were prudent, based on the AUC's review of the variances between the internally-approved cost estimates and the actual 2016 costs incurred and AltaGas' explanations for these variances.

Considering the Individual projects within the Station Refurbishment Program

In Decision 20522-D02-2016, the AUC approved the need on a forecast basis, for each of the Station Refurbishment Program projects, for purposes of capital tracker treatment in 2016. The AUC also determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable.

In this decision, the AUC found that:

(a) with respect to the true-up of 2016 actual costs, there was no evidence on the record to indicate that any of the station replacement and refurbishment projects included in the Application were not required in 2016;

(b) with respect to the scope, level and timing of each of the PMS, TBS and PRS station replacement and refurbishment projects carried out in 2016, these projects were generally consistent with the scope, level and timing of the work outlined in the business case approved in Decision 20522-D02-2016; and

(c) the actual scope, level, timing and costs of the work undertaken in 2016 were prudent.

Accordingly, the AUC found that the Station Refurbishment Program and each of the associated PMS, TBS and PRS station replacement and refurbishment projects approved in Decision 20522-D02-2016, and carried out in 2016, satisfied the project assessment requirement of Criterion 1 for 2016.

Considering individual projects within Gas Supply Program

In Decision 20522-D02-2016, the AUC approved a 2016 gas supply placeholder of $661,250, as AltaGas was anticipating 2016 expenditures associated with a Gas Supply Project to address the potential imminent loss of existing gas supply but was still in the process of examining potential alternatives and the associated costs.

In the Application, AltaGas advised that it was unclear when, or to what extent, area producers would be successful in accessing liquids-rich production. AltaGas therefore was continuing to monitor the situation. In the interim, since no assets were placed into service specifically related to gas supply, AltaGas proposed refunding the K factor adjustment related to the 2016 placeholder.

Since no assets were placed into service specifically related to gas supply, the AUC approved AltaGas' request to refund to customers the K factor adjustment.

<u>Accounting Test under Criterion 1</u>

AltaGas used the following assumptions in its accounting test:

Table: AltaGas' 2016 capital tracker true-up accounting test assumptions

2016 I-X index	0.90%
2016 Q factor	1.36%
Weighted average cost of capital (WACC) rate embedded in AltaGas' going-in rates used in the first component of the accounting test	6.708%
Actual 2016 WACC rate used in the second component of the accounting test	6.120%

The AUC noted that:

- The 2016 I-X index of 0.90 percent was approved in Decision 20823-D01-2015.
- The 2016 Q factor of 1.36 percent was based on the billing determinants forecast approved in Decision 20823-D01-2015.
- AltaGas' actual 2016 WACC rate of 6.120 percent was based on the actual cost of debt of 4.541 percent, the approved equity thickness of 41 percent and the approved return on equity ("ROE") of 8.3 percent, as determined in the 2016 generic cost of capital Decision 20622-D01-2016.
- AltaGas' actual 2016 cost of debt of 4.541 per cent, as reported in its 2016 Rule 005 filing, was a blend of its new $45 million long-term debt issued in 2016 with a coupon rate of 4.20 per cent, and rates for six prior debt issues dating back to 2009.

The AUC found that:

(a) AltaGas' used the correct WACC, I-X and Q factor assumptions and values for the first component of the accounting test;

(b) AltaGas' 2016 actual WACC of 6.120 per cent used in the second component of its accounting test, based on the 2016 actual cost of debt of 4.541 per cent, as well as the approved equity thickness of 41 per cent and the approved ROE of 8.3 per cent from Decision 20622-D01-2016, were reasonable; and

(c) AltaGas' accounting test model sufficiently demonstrates that all of the actual expenditures for a capital project were, or a portion was, outside the normal course of the company's ongoing operations, as required to satisfy the accounting test component of Criterion 1.

<u>Criterion 1 Conclusion</u>

The AUC concluded that:

- AltaGas' programs or projects proposed for capital tracker treatment in 2016 on an actual basis satisfied the project assessment requirement of Criterion 1.
- All of AltaGas' actual expenditures for a capital project were, or a portion was, outside the normal course of the company's ongoing operations, as required to satisfy the accounting test component of Criterion 1.

<u>Criterion 2 – ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party</u>

Because the driver or drivers (e.g., replacement of existing assets, external party, growth) for each project or program included in AltaGas' 2016 capital tracker true-up had not changed since they were approved for capital tracker treatment, the AUC did not need to reassess these programs or projects against the Criterion 2 requirements.

For the three 2016 PRP Projects, given AltaGas' confirmation that there were no changes to the drivers of any of its previously approved capital tracker programs, the AUC found that these three projects satisfied the requirements of Criterion 2.

Criterion 3

The AUC found that, based on its review of AltaGas' calculations:

(a) AltaGas interpreted and applied the Criterion 3 two-tiered materiality test correctly for the purposes of its 2016 capital tracker true-up; and

(b) each of AltaGas' proposed capital tracker programs for 2016 exceeded the materiality thresholds, and therefore satisfied Criterion 3.

2016 K factor True-up Calculation and Order

Based on its review of AltaGas' calculations, the AUC found that AltaGas' methodology to determine the 2016 K factor true-up amount satisfied the requirements set out in Decision 2012-237 and Decision 2013-435

The AUC therefore approved:

(a) the 2016 K factor true-up refund amount of $513,259; and

(b) AltaGas' proposal to refund this amount as part of either AltaGas' application to establish the 2018 PBR rates or in its next Rate Rider F application, whichever occurs first.

Alberta Utilities Commission – Commission-Initiated Proceeding to Review the Terms and Conditions of Service of Regulated Rate Service Providers (Decision 22091-D01-2017)

Terms and Conditions of Service – Liability of Rural Landowners for Abandoned Energy Facilities – Farmers Advocate

In this decision, the AUC considered proposed amendments to the terms and conditions of service of EPCOR Energy Alberta GP Inc. ("EPCOR"), Direct Energy Regulated Services ("DERS"), ATCO Electric Ltd. ("ATCO") and FortisAlberta Inc. ("Fortis") (collectively, the "Companies"). Specifically, the AUC considered the proposed amendments to ensure that rural property owners would not be liable for electrical distribution charges related to an energy company's oil and natural gas facilities located on their land in circumstances where the rural property owner has not requested the service.

In this decision, for the reasons further summarized below, the AUC:

(a) Approved, with slight modification, the amendments proposed by EPCOR and DERS, to be effective no later than December 1, 2017; and

(b) Conditionally approved the amendments proposed by ATCO and Fortis, pending the outcome of any resulting from AUC Rule 021: *Settlement System Code Rules* ("*Rule* 21") and AUC Rule 028: *Natural Gas Settlement System Code* ("*Rule 28*") consultations.

Background

On October 20, 2016, the AUC issued notice that it would, on its own initiative, review certain terms and conditions of the regulated rate service of EPCOR (the "EPCOR T&Cs") and DERS (the "DERS T&Cs"). The proceeding was initiated after the Farmers' Advocate Office ("Farmers' Advocate") advised the AUC that some rural landowners were being billed by regulated rate service providers as the customer of record for oil and gas sites located on their property after the energy companies had abandoned their facilities and stopped paying the electric distribution charges.

In a process letter issued on January 9, 2017, the AUC expanded its review to include the terms and conditions of service distribution companies ATCO (the "ATCO T&Cs") and Fortis (the "Fortis T&Cs"), after receiving a complaint from the Farmers' Advocate that a rural property owner had been charged an oilfield rate by ATCO for service requested by a now insolvent energy company.

EPCOR and DERS Proposed Amendments to Terms and Conditions

Table: EPCOR Proposed Amendment and AUC Directed Adjustment

EPCOR's proposed amendment to Article 8.11 of the EPCOR T&Cs and AUC directed adjustment
8.11 Owner's Liability for payment In circumstances where: (a) there is no Customer of Record registered on the accounting records of EEA; and (b) there are no other occupants of the Site who continue to receive Service, the Property Owner shall be deemed to be the Customer of Record and shall be liable for payment for Services provided in accordance with the Regulated Rate Tariff until the date a new

Customer of Record is determined by EEA provided that a rural Property Owner will not be made responsible for paying Regulated Rate Tariff charges related to Service for an energy company's oil and natural gas facilities located on the rural Property Owner's site or sites unless the rural Property Owner directly requested the Service or will receive a benefit from the continuation of the Service. The Property Owner when deemed to be the Customer of Record under this provision shall be liable for all charges relating to identifying, searching for and contacting the Property Owner as a result of there being no Customer of Record for the Site.

Table: DERS Proposed Amendment and AUC Directed Adjustment

DERS' proposed amendment to Article 3.7 of the DERS T&Cs and AUC directed addition of definition and adjustment to Article 3.7
"Property Owner" means: (a) the registered owner of a parcel of land in the register maintained by the Registrar of Titles under the *Land Titles Act*; or (b) a person who has purchased the parcel from the person mentioned in sub clause (a) pursuant to an agreement for purchase and sale. **3.7 Owner's Liability for Payment** In circumstances where: (a) there is no Customer registered on the account records of DERS; and (b) there are no other occupants of the Site who continue to receive service The Property Owner will be deemed to be the Customer of Record and will be liable for payment for services provided in accordance with the Regulated Rate Tariff until the date a new Customer is determined by DERS, provided that a rural Property Owner will not be deemed to be the Customer of Record or made responsible for paying Regulated Rate Tariff charges related to service for an energy company's oil and natural gas facilities located on the rural property owner's sites unless the rural Property Owner directly requested the service or will receive a benefit from the continuation of the service. The Property Owner when deemed to be the Customer of Record under this provision shall be liable for all charges relating to identifying, searching for and contacting the Property Owner as a result of there being no Customer of Record for the Site.

The AUC found that EPCOR and DERS' proposed amendments achieved the objective set out in the AUC's notice of proceeding. Specifically, the AUC found, that, with the slight modifications shown above (blue), the amendments proposed by EPCOR and DERS would ensure that rural property owners were not charged for distribution charges related to an abandoned oil and gas site located on their property.

The AUC directed that DERS and EPCOR adjust the proposed amendments by inserting the word "directly" between "Property Owner" and "requested," where the proposed amendments of EPCOR and DERS state "…unless the rural Property Owner requested the Service…" ("service" in DERS' case).

<u>ATCO's and Fortis' Retailer Terms and Conditions</u>

The AUC found that the amendments proposed by ATCO and Fortis would ensure that rural property owners are not improperly billed for service to an oil and gas site located on their property. However, the AUC noted that this issue was also raised in the context of a review of Rule 021 and Rule 028 in an industry consultation session held in February 2017. A working group was formed to examine the matter, but its review was suspended pending the completion of this proceeding. The AUC considered that a resumption of the review by stakeholders might result in recommendations that directly impact the business processes proposed by ATCO and Fortis in the amendments to their own terms and conditions.

Therefore, the AUC conditionally approved the amendments proposed by ATCO and Fortis, subject to the outcome of the Rule 021 and Rule 028 consultations, at which time the AUC would revisit its conditional approval and determine whether the present amendments should remain in force or be further amended.

<u>Order</u>

The AUC ordered the companies to make their proposed amendments with the changes directed by the AUC.

TransAlta Corporation – 2015-2016 Transmission General Tariff Application (Decision 22651-D01-2017)

General Tariff Application – Electricity Transmission

On May 12, 2017, TransAlta Corporation, as Manager of the TransAlta Generation Partnership ("TransAlta"), filed an application with the Commission requesting approval of its 2015-2016 General Tariff Application ("GTA") (the "2015-2016 GTA" or "Application").

In the Application, TransAlta requested the AUC approve:

(a) a revenue requirement of $4.79 million for 2015;

(b) revenue requirement of $6.14 million for 2016

(c) transmission facility owner (TFO) terms and conditions of service (T&Cs) for 2015 and 2016; and

(d) reconciliation of certain deferral accounts proposed by TransAlta.

In this decision, the AUC approved the Application, subject to certain adjustments and directions summarized below.

Background

TransAlta's transmission facilities consist of the transmission assets owned by TransAlta and located on First Nations Lands, and of subsequent investments in these assets and others, all on First Nations' Lands (the "Withheld Assets").

TransAlta, together with AltaLink via the Operating and Maintenance ("O&M") Agreement, maintains and operates the Withheld Assets. With a small administrative and operations team, TransAlta provides overall control and direction to AltaLink who, as TransAlta's sole contractor, performs the day-to-day operating and capital maintenance, as well as any Alberta Electric System Operator ("AESO") direct assigned capital projects.

Operating, Maintenance, and Administrative Costs

The AUC approved, as filed, TransAlta's applied for Direct Operation and Maintenance Costs, based on finding the following expenses to be reasonable:

Table: Direct Operation and Maintenance Costs

Description	*2014 actual*	*2015 forecast*	*2016 forecast*
	($000)		
Supervision and engineering	*276*	*324*	*340*
Miscellaneous transmission expense	*586*	*578*	*631*
Right-of-way payments	*484*	*485*	*507*
Linear property tax	*422*	*426*	*464*
Total	*1,768*	*1,813*	*1,942*

With the exception of miscellaneous general expenses (highlighted below), the AUC found to be reasonable the following administrative and general expense items in the amounts applied-for by TransAlta:

Table: Administrative and General Expenses

Description	2014 actual	2015 forecast	2016 forecast
	($000)		
Administrative and general salaries	176	268	272
Administrative corporate	52	79	80
Outside services employed	39	14	31
Insurance premiums	2	3	1
Injuries and damages	500		
Commission expenses	(114)	(5)	
Miscellaneous general expenses	80	45	333
Total	736	405	718

Table: Miscellaneous General Expenses

	2014 actual	2015 forecast	2016 forecast
	($000)		
First Nations advisory committee funding	80	18	20
Community building sponsorships	-	27	33
Annual cooperation agreement	-		280
Total	80	45	333

With respect to the First Nations advisory committee ("FNAC") expenses, the AUC approved the amounts as filed based on the following findings:

(a) FNAC meetings helped to improve the relationship between TransAlta and the First Nations, as well as help TransAlta achieve its public utility mandate; and

(b) These expenses were reasonable.

Considering community building sponsorships

The AUC found that support expenditures, like the community-building sponsorship program and the community investment initiative of TransAlta, can foster goodwill among the community. Developing goodwill and relationship building with a community may assist the utility in obtaining community support in carrying out the utility's operations. However, the AUC noted that it has consistently denied recovery of these types of expenditures from ratepayers for a number of reasons, including:

- Ratepayers may not desire to support the same organizations that utility management or shareholders would support. Ratepayers have the right to choose to support whichever worthy causes they choose through their own donation dollars and should not be expected to provide the funds to support the causes that the utility has chosen; and

- The sponsorships or donations do not demonstrate a direct benefit related to the provision of utility service.

The AUC found that donations can be considered as payments made by the shareholder to support the goodwill of the utility.

The AUC acknowledged it can be in the public interest to respect, honour and to accommodate rights of the Indigenous peoples of Canada where appropriate. In some circumstances, community support expenditures by a utility may be aligned with the public interest, depending on the impact of the utility's operations on these rights and the nature of the support provided. In such circumstances, the inclusion of community support expenditures in revenue requirement and rates may be justified.

However, in this case, the AUC found that TransAlta failed to establish that the proposed community support expenditures were in the public interest in light of the activities being carried out by the utility in the relevant Indigenous communities and the impact of TransAlta's operations on the rights of the people in these communities. Accordingly, the AUC followed its previous well-established practice of denying community building sponsorship costs. The AUC directed TransAlta to remove all costs associated with donations or sponsorships from the 2015 and 2016 revenue requirement forecasts.

Transmission Rate Base

Table: TransAlta Applied-for Rate Base

	2014 actual	2015 forecast	2016 forecast
Mid-year net property	20,507	22,293	35,345
Working capital	289	333	373
Rate base	20,795	22,627	35,718
Net mid year contributions	(51)	(49)	(47)
No cost capital	(68)	(8)	0
Net rate base	20,677	22,525	35,671

Additions to rate base

The AUC approved the following rate base additions:

(a) TransAlta's applied-for actual capital maintenance expenditures and associated rate base additions;

(b) TransAlta's forecasted capital additions for the purposes of determining TransAlta's revenue requirement in the test period.

Working Capital

The AUC found to be reasonable TransAlta's proposal to adopt working capital ratios approved for AltaLink in respect of the 2015-2016 test period, given TransAlta's small size and closely integrated operations with AltaLink.

The AUC found that:

(a) TransAlta's necessary working capital calculations were accurate; and

(b) TransAlta's working capital ratios and lead lag data match those in AltaLink's third compliance filing for its GTA.

Deferral Accounts

The AUC approved the following deferral account reconciliations for the years 2013 and 2014:

- capital deferral account reconciliation for directly assigned capital projects;
- operating deferral account reconciliation for property taxes and payments in lieu of property taxes; and
- operating deferral account reconciliation for actual tower payments versus approved placeholders.

Millar Western Forest Products Ltd. – Post-Construction Comprehensive Sound Level Survey (Decision 22535-D01-2017)
Post-construction Sound Survey – AUC Rule 012: Noise Control – Class A2 Ambient Adjustment

Background

Millar Western Forest Products Ltd. ("Millar Western") is the approval holder of AUC Power Plant Approval U2012-2373 (the "Approval") to construct and operate a 5.2-megawatt (MW) Biogas Power Plant (the "Biogas Plant"). Condition 4 of the Approval required Miller Wester to conduct a comprehensive noise survey at the power plant within six months after the power plant was commissioned and report the findings to the AUC.

In this decision, the AUC considered the post-construction comprehensive sound level survey ("CSL Survey") for the Biogas Plant, filed by Miller Western pursuant to Condition 4.

Under Rule 012, a CSL survey is valid if it meets the criteria outlined in Rule 012 and a facility is in compliance if the comprehensive sound level measured during representative conditions is equal to or lower than the established permissible sound level.

Specifically, in this decision, the AUC considered:

(a) the CSL Survey for the Biogas Plant, which measured the sound impacts at four dwellings, receptors R1, R2, R3, and R4; and

(b) Miller Western's requested Class A2 Ambient Adjustment to the permissible sound level ("PSL") with respect to two receptors (R1 and Receptor R3) for both daytime and nighttime periods (the "A2 Adjustment Request").

Comprehensive Sound Level Survey

With respect to the CSL Survey, the AUC found that:

(a) the CSL Survey was conducted in accordance with the requirements of AUC Rule 012: *Noise Control* ("Rule 12");

(b) the Biogas Plant was in compliance with the PSL requirements at receptors R2 and R4; and

(c) the dwelling referred to as Receptor R3 had been demolished and, accordingly, the AUC did not need to assess PSL compliance at Receptor R3.

Class A2 Ambient Adjustment

The AUC approved an A2 adjustment during the nighttime periods for Receptor R1 and found that, with the A2 adjustment applied, the Power Plant complied with the PSL at Receptor R1. The AUC did not approve the A2 adjustment for Receptor R3, given that there was no longer a dwelling at that location.

Decision

Based on the above findings, the AUC found the CSL Survey for the Biogas Plant met Condition 4 of the Approval.

With regard to the applied-for A2 adjustment, the AUC approved the A2 adjustment to the PSL for the nighttime period at Receptor R1.

NATIONAL ENERGY BOARD

TransCanada PipeLines Limited – Application for Approval of Dawn Long Term Fixed Price Service (RH-003-2017)

Service and Toll Application – Mainline Service Offering – Long Term Fixed Price Service

On 26 April 2017, TransCanada PipeLines Limited ("TransCanada") filed an application under Parts I and IV of the *National Energy Board Act* ("*NEB Act*") (the "Application"), requesting the NEB approve:

(a) the Dawn Long Term Fixed Price ("LTFP") service (the "Dawn LTFP Service" or "Service");

(b) the tolling methodology and tolls for the Service; and

(c) consequential amendments to the Canadian Mainline Gas Transportation Tariff.

<u>The TransCanada Dawn LTFP Service Application</u>

In the Application, TransCanada submitted, among other things, that:

(a) it negotiated the Dawn LTFP service with western Canadian natural gas producers and subsequently offered it to all prospective shippers through an open season process;

(b) in total, 27 new long-haul contracts were executed with 23 parties for a total of 1.5 petajoules per day (PJ/d), with 1 November 2017 specified as the service commencement date for 90 percent of the contract quantities;

(c) the Dawn LTFP shippers were all producers in the Western Canada Sedimentary Basin ("WCSB"), none of which otherwise hold firm service contracts on the Mainline; and

(d) The net revenue associated with the service was expected to total approximately $2.0 billion over the term of the Dawn LTFP contracts.

Key terms of the Service included:

- A 10-year contract term, with the option to reduce the term of all or a portion of the contract quantity by one to five years;
- A fixed demand toll of $0.77 per gigajoule per day (GJ/d), inclusive of the applicable abandonment surcharge and delivery pressure toll, with a higher fixed Dawn LTFP toll applying in the final two years if the shipper elects to reduce its contract term (the "Dawn LTFP Toll");
- A receipt point of Empress and a delivery point of the Union Southwest Delivery Area ("Dawn"), with no diversion or alternate receipt point rights but with the ability to nominate to select Secondary Delivery points on the Great Lakes Gas Transmission Company ("GLGT") System on a reasonable efforts basis; and
- The service was not renewable but could be converted to Firm Transportation (FT) service at the end of the contract term (with 2-years notice).

Figure 1: TransCanada Mainline System showing Empress and Dawn

For the reasons summarized below, the NEB concluded that the Dawn LTFP Service was an appropriate competitive response and approved the Service and tolling methodology as applied-for.

<u>Requirements of the NEB Act</u>

The NEB explained that Part IV of the *NEB Act* prescribes the NEB's mandate for traffic, tolls and tariff matters:

- Section 62 of the *NEB Act* prescribes that tolls must be just and reasonable and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.
- Section 67 of the *NEB Act* prohibits a company from making any unjust discrimination in tolls, service or facilities against any person or locality.

To determine whether tolls are just and reasonable and not unjustly discriminatory, the NEB has historically relied on fundamental tolling principles, including the principles of cost-based/user-pay tolls, no acquired rights, and economic efficiency.

NEB Findings

Need for Dawn LTFP Service

The Board finds that a competitive Mainline service, such as offered by the Dawn LTFP Service, was required to attract long-term, long-haul contracts from WCSB producers seeking access to eastern markets. The NEB found, in support of this conclusion, that:

(a) there were currently no Empress to Dawn FT contracts in place, and Dawn LTFP shippers did not hold any firm service on the Mainline; and

(b) current FT service tolls to Dawn were economically prohibitive for producers, and producers would not contract for services when it was not economic to do so.

Rejecting arguments by interveners that the Service was not required given TransCanada's ability to incent WCSB volumes through pricing discretion, the NEB found that:

(a) long-term firm contracts provide significant benefits for the Mainline relative to discretionary services, including toll certainty and stability; and

(b) the Service provided Dawn LTFP shippers with toll certainty, which would not be achieved by relying on IT (interruptible) service.

The NEB also affirmed its findings from previous Mainline related decisions, that it has provided TransCanada with tools to meet competition with the expectation that TransCanada should meet market forces with market solutions. While acknowledging that the Mainline had returned to relative financial health in recent years, the NEB found that the trend of declining long-haul contracting was clear, and the ongoing issues necessitating proactive solutions remained. The NEB considered that Dawn LTFP Service was an innovative service that used underutilized capacity to attract long-term, long-haul contracts from Empress to Dawn, for the benefit of the Mainline and its shippers.

Benefits and impacts of Dawn LTFP Service

The NEB found that the Service would provide substantial benefits to the Mainline and its shippers. Specifically, the NEB found that the estimated $2 billion of total net revenue associated with the Service would significantly reduce the Mainline revenue requirement allocated to other shippers during the term of the Service.

In the NEB's view, a key consideration was that Dawn LTFP service would provide a benefit to the Mainline. While the NEB acknowledged the inherent estimation risk to forecasted costs, the NEB concluded that this risk had largely been mitigated by TransCanada, such that there was reasonable certainty that a significant net revenue benefit would occur.

However, to allow the NEB and shippers to track the net revenue benefit of the Service, the NEB directed TransCanada:

(a) to separately track and report annually the actual costs and revenues related to the Dawn LTFP Service; and

(b) to consult with its shipper group to determine an appropriate format for this reporting, which may be filed as part of TransCanada's quarterly surveillance reports.

Matters of cost allocation should be addressed on system-wide basis

The NEB found that concerns raised by intervenors regarding cost allocation matters would be more appropriately addressed on a system-wide basis, in future proceedings considering all Mainline costs and revenues. Future toll proceedings would require the allocation of Dawn LTFP related costs and revenues to result in just and reasonable tolls, and tolls and services that are not unjustly discriminatory. The NEB stated that it expects that the benefits derived from Dawn LTFP service would be shared in a fair manner amongst Mainline segments and users.

Similarly, the NEB found that the merits of the Industrial Gas Users Association's ("IGUA") proposal to include unallocated TBO capacity revenues in the discretionary miscellaneous revenues forecast were more appropriate for evaluation during the 2018 to 2020 tolls application.

Dawn LTFP Toll is just and reasonable

The NEB found the Dawn LTFP Toll to be just and reasonable.

Considering its established tolling principles in the context of the competitive circumstances facing WCSB producers and the Dawn market, the NEB's conclusion was based on findings including:

- The $0.77/GJ/d Dawn LTFP Toll was a negotiated rate, and not determined on a cost-of-service basis.

- While the cost-based/user-pay principle is an important principle that helps guide the Board under Part IV of the NEB Act, the competitive circumstances involving the Dawn hub justified the negotiated approach.

- By offering the negotiated toll, significant volumes would be attracted and net revenues, estimated at $2 billion, would be generated that would otherwise not occur.

- While the Dawn LTFP toll represents a departure from the cost-based/user-pay principle, economic efficiency would be promoted through increased system utilization and the net lowering of existing Mainline tolls.

No unjust discrimination

The NEB concluded that the Dawn LTFP Toll and Service were not unjustly discriminatory, based on its findings that:

(a) the circumstances under which the Service would be provided were not substantially similar as other services, given the unique competitive pressures existing at the Dawn and the Service having been designed to respond to a specific competitive circumstance;

(b) the Dawn LTFP Service was different traffic than that of other services, based on differing service attributes from FT service including the 10-year term, the lack of alternate receipt point and diversion rights on the Mainline, and the lack of renewal rights; and

(c) accordingly, the Dawn LTFP Service could be charged at a different rate than FT service without offending the prohibition against unjust discrimination set out in section 67 of the NEB Act.

Modifications to the Service would undermine the negotiated package

The NEB rejected numerous changes to the Service suggested by interveners. The NEB stated that it reviewed the suggested changes in the context of the Service being a negotiated package between a group of producers and TransCanada.

The NEB found, that while it had the ability to modify terms of a service in any application, in this case directing modifications to a negotiated package would undermine the negotiation that occurred.

The NEB decided to treat the Dawn LTFP Application as a package deal. Therefore, its limited its consideration to whether that package resulted in tolls that were just and reasonable and service and tolls that were not unjustly discriminatory.

Prudence of TransCanada's TBO contracting decisions

The NEB affirmed its findings from previous decisions that it does not require TransCanada to seek pre-approval before it enters into TBO agreements. Prudence reviews are appropriately undertaken when TBO costs are applied to be recovered from Mainline shippers in future toll applications.

The NEB stated that it expects TransCanada to optimize net revenue benefits for the Mainline and its shippers over the term of the Service and that this was largely affected by GLGT TBO costs. Future optimized flow-splits and TBO contract quantities would depend on a number of factors, including long-haul contracting decisions and available capacity over the Northern Route.

The NEB noted that in future toll applications, it may disallow any costs found to have been imprudently incurred.

In light of the significant Dawn LTFP volumes and the affiliate relationship with TBO contracting parties, the NEB stated that it expects TransCanada to provide sufficient information in future toll applications for interested parties to assess the prudence of its TBO arrangements related to the Service.

Since TransCanada has the best information that drives its decisions on TBO quantities, the NEB found it reasonable that TransCanada share this information with interested parties in its toll applications.

Based on the above, the NEB directed TransCanada to include, in all future toll proceedings seeking to recover TBO costs related to Dawn LTFP, disaggregated information to support the prudence of Dawn LTFP related TBO costs, including:

(a) information on TBO contracts;

(b) TBO costs, and

(c) Dawn LTFP contract demand and available capacity on relevant Mainline segments.

The NEB further directed that TransCanada provide support for this information including a detailed explanation, including any key assumptions, of TransCanada's assessment for determining its TBO contracts associated with Dawn LTFP Service.

<u>Decision</u>

The NEB approved the Application as filed.

The NEB directed TransCanada to separately track and report annually the actual costs and revenues related to Dawn LTFP service and to provide, in all future toll proceedings, disaggregated information to support the prudence of Dawn LTFP service-related TBO costs.