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FortisBC Alternative Energy Services Inc.

Application for Approval of the Fiscal 2018/2019 Revenue Requirements and Cost of Service Rates for the Thermal Energy Service to Delta School District No. 37

Decision
and Order G-84-19

April 16, 2019

Before:
W. M. Everett, QC, Panel Chair
A. K. Fung, QC, Commissioner
M. Kresivo, QC, Commissioner

TABLE OF CONTENTS

Page no.

Executive summary

On February 8, 2018, FortisBC Alternative Energy Services Inc. (FAES) applied to the British Columbia Utilities Commission (BCUC) for approval of its revenue requirements and rate for the thermal energy service to Delta School District No. 37 (DSD). The application proposes a switch from the current Market Rate mechanism to the cost of service (COS) rate (COS Rate) of $0.223 per kilowatt-hour (kWh), effective July 1, 2018, for the fiscal and contract year from July 1, 2018 to June 30, 2019 (Application).

Several significant regulatory proceedings involving FAES and DSD have taken place, dating back to the utility's original 2011/2012 application for the construction and operation of the thermal energy project at 19 individual sites for the DSD, to various other rate applications in subsequent years, all of which precede and set the context for this Application. The outcomes of those past regulatory proceedings establish the facts of this case which are undisputed by both parties, most notably:

- Rates and rate design are established by an Energy System Rate Development Agreement (RDA) and individual Energy System Service Agreements (ESSAs) entered into between FAES (originally FortisBC Energy Inc.) and DSD.
- FAES and DSD negotiated an ESSA for each of the 19 sites and an overall RDA that pools the costs of providing service to each ESSA into a single rate. The RDA also contains a deferral account, the District Deferral Account (DDA), to capture variances between the Annual Cost of Service and the actual revenues collected, with the balance to be recovered in future rates.
- The original 2011/2012 capital and rate proceedings were reviewed by the BCUC through a public process and resulted in the BCUC's approval of the negotiated contracts between FAES and DSD. The validity of those previous orders and decisions has not been challenged prior to this proceeding.

After considering the evidence and submissions, the Panel makes the following findings and determinations:

- It is just and reasonable to approve the Application by giving effect to FAES' right to trigger the switch from the Market Rate to the COS Rate at this time. Further, the Panel is not persuaded that it would be in either FAES' or DSD's best interest for the switch to be further delayed (beyond the accommodation set out in the last finding below) and declines to do so.
- The Panel rejects DSD's argument that the alleged collateral representations ought to be interpreted in such a way as to disallow FAES the remedy sought. The Panel also rejects DSD's argument that it has established an alleged promissory estoppel which would preclude the BCUC from granting FAES the remedy sought.
- The Panel finds the evidence offered by certain DSD witnesses irrelevant to the task of determining the timing and propriety of the proposed switch from the Market Rate to the COS Rate as stipulated in the RDA. The Panel further declines to "reassess" the CPCN on the basis that the Panel lacks jurisdiction to do so.
- The Panel finds that DSD has not provided adequate evidence to rebut the presumption of prudence and therefore denies DSD's request for a prudency review of the project capital costs. The Panel also finds that FAES has taken appropriate and reasonable steps to improve the optimization of the TES.
- The Panel finds it is just and reasonable for FAES to recover its prudently incurred costs of providing service to DSD, including an allowed return on investment. These costs are clearly defined in the RDA and there is sufficient evidence on the record in this proceeding to show that the Annual Cost of Service amounts are reasonable and in accordance with the RDA.

- Finally, the Panel finds it reasonable to delay the timing of the switch to the COS Rate to July 1, 2019 to provide some accommodation for DSD's unique budgeting constraints. The Panel therefore declines FAES' request to make the COS Rate permanent effective July 1, 2018.

Given that the Market Rate was approved by the BCUC on an interim basis by Order G-77-18, the Panel approves the Market Rate on a permanent basis effective July 1, 2018. The Panel further orders that the difference between the actual Annual Cost of Service and the revenues collected for the Fiscal 2018/19 rate year, plus an amount for Allowance for Funds Used During Construction (AFUDC), be recorded in the DDA for recovery over the remaining years of the RDA term, beginning July 1, 2019.

1.0 Background and Introduction

1.1 Application and Approvals Sought

On February 8, 2018, pursuant to sections 59-61 of the *Utilities Commission Act* (UCA), FortisBC Alternative Energy Services Inc. (FAES) applied to the British Columbia Utilities Commission (BCUC) for approval of its revenue requirements and rates for the thermal energy service to Delta School District No. 37 (Delta SD, DSD). The application proposes a switch from the current market rate to the cost of service (COS) rate (COS Rate) of $0.223[1] per kilowatt-hour (kWh), effective July 1, 2018, for the fiscal and contract year from July 1, 2018 to June 30, 2019 (Application).

As part of the Application, FAES also applied (pursuant to section 89 of the UCA) for approval of the COS Rate of $0.223 per kWh on an interim and refundable basis effective July 1, 2018, if the Panel is unable to render its decision on the Application before July 1, 2018. The BCUC approved the existing market rate mechanism and resulting market rate on an interim and refundable basis, effective July 1, 2018.[2]

1.2 Regulatory History and BCUC Decisions

A number of previous regulatory proceedings involving FAES and DSD, and the evidence and decisions therein, have implications for this Application and thus are referenced throughout this decision and are discussed below.

1.2.1 Application for a Certificate of Public Convenience and Necessity for Approval of Contracts and Rate to Provide Thermal Energy Service to DSD

On November 28, 2011, FortisBC Energy Inc. (FEI) filed an application for a Certificate of Public Convenience and Necessity (CPCN) for the construction and operation of thermal energy projects at 19 individual sites for the DSD. FEI also applied for approval of the rates and rate design established by an Energy System Rate Development Agreement (RDA) and individual Energy System Service Agreements (ESSAs, Service Agreements) entered into between FEI and DSD (CPCN Application). The application was filed pursuant to sections 45, 46, and 59 to 61 of the UCA.

The project entailed the construction and operation of thermal energy upgrades at 19 of DSD's buildings over two years, which consisted of: the replacement of eight conventional boilers with high efficiency, condensing boilers; the conversion of existing thermal plants to geo-exchange systems with peaking gas boilers at 11 sites; and the retrofitting/replacement of existing infrastructure at all 19 sites to accept new technologies. The total project costs were estimated to be $6.5 million, with DSD providing a Contribution in Aid of Construction (CIAC) of $1.357 million. FEI would own, operate and maintain the new thermal plants once completed.[3]

FEI and DSD negotiated an ESSA for each of the 19 sites and an overall RDA that pools the costs of providing service to each ESSA into a single rate. The single, pooled rate is based on a COS model, which covers capital costs, depreciation expenses, operating and maintenance (O&M) expenses, overhead costs, debt financing and a return on investment. The RDA also contains a deferral account, the District Deferral Account (DDA), to capture variances between the COS and the actual revenues collected, with the balance to be recovered in future rates.[4]

[1] The F2018/19 COS Rate was amended from $0.223 per kWh to $0.253 per kWh in an evidentiary update to the Application filed on June 13, 2018.
[2] Exhibit A-3, Order G-77-18.
[3] FEI Application for a CPCN and Approval of Contracts and Rate to Provide Thermal Energy Service to DSD dated November 28, 2011 (CPCN Application), pp. 1-2.
[4] CPCN Application, pp. 2-3.

FEI stated that the RDA also contemplates a "Market Rate" (Market Rate, MR) which was described as a way to resolve "the transitional challenge of moving from the current costs of energy to the cost of service rate without causing an increase beyond what the [DSD] might experience using their current natural gas equipment."[5] FEI submitted that DSD will pay the Market Rate for thermal energy until it switches to the COS Rate, with any variances between the actual revenues collected and the Annual Cost of Service to be captured in the DDA. FEI also indicated that the RDA gave FEI the ability to apply to the BCUC to move to the COS Rate after an initial transition period.[6]

On March 9, 2012, the BCUC issued its decision and Order G-31-12 (CPCN Decision) granting the CPCN on the condition that the RDA and the Service Agreements be assigned to an affiliate of FEI.

As part of the CPCN Decision, the BCUC denied approval of the proposed rate and rate design as applied for and as set out in the RDA and Service Agreements. The BCUC set out a number of requirements and revisions required for the approval of the rate and rate design as well as a number of required reports and schedules to be filed with the BCUC.

In the CPCN Decision, the BCUC questioned the appropriateness of the traditional COS rate-setting mechanism negotiated by the parties, indicating that it was not convinced a COS model was the most appropriate approach in a competitive environment. The BCUC stated that it was:

> …concerned with the cost risks that Delta SD will be assuming with a COS model, which will hold the current and future Boards of Trustees of the SD accountable in the initial contractual term of 20 years. By using a COS model, the assumption of risk lies largely at the hands of the customer, in this case the DSD. In other alternative pricing models the forecast or costs risks are more balanced between the service provider and the customer.[7]

Concerning the risks assumed by DSD, the BCUC noted that the Service Agreements do not appear to provide significant performance guarantees which would hold FEI accountable for operational obligations, such as service reliability, greenhouse gas (GHG) reductions or energy savings.[8] The BCUC noted that one of the primary drivers for the project is the reduction of GHG emissions, but also noted that it was unaware of any performance guarantees that would ensure the thermal energy system (TES) would achieve the anticipated GHG reductions.[9]

Despite the aforementioned concerns, the BCUC found that the Service Agreements were negotiated in good faith by two sophisticated parties, and as such, it was inappropriate to impose a different rate-setting mechanism. However, the BCUC gave DSD and FEI a 30-day window to review the CPCN Decision and, if appropriate, reconsider and renegotiate the Service Agreements in accordance with the guidance provided by the BCUC. FEI and DSD were encouraged to revisit the COS Rate and consider a pricing model that might better allocate risk between the parties.

Notwithstanding the foregoing, the BCUC indicated that it would accept a rate and rate design based on the proposed 60/40 debt equity capital structure with the following modifications:[10]

- The rate schedule is restricted to DSD's current and future sites;
- The rate must include allowances for capitalized overhead, cash working capital, inflation and escalation on capital replacements/sustaining capital items and replace "unpaid time" by FEI employees with "paid time";

[5] CPCN Application, p. 3.
[6] Ibid.
[7] FEI Application for a CPCN and Approval of Contracts and Rate to Provide Thermal Energy Service to DSD Decision dated March 9, 2012 (CPCN Decision), p. 84.
[8] Ibid., p. 80.
[9] Ibid., pp. 64, 84.
[10] CPCN Decision and Order G-31-12.

- The establishment of a cost of debt rate based on an entity with a BBB rating with an additional premium to reflect the extra cost to arrange an incremental small debt issue; and
- The provision for a maximum 50 basis points premium above the benchmark Return on Equity (ROE) or a lower negotiated equity premium.

In response to the BCUC's conditions for approval of the CPCN outlined in the CPCN Decision, FEI filed proof of assignment of the RDA and Service Agreements to its affiliate FAES and subsequently, the BCUC issued a CPCN to FAES.[11]

1.2.2 Order G-71-12 Compliance Filing

On April 3, 2012, in compliance with the CPCN Decision, FAES filed with the BCUC an executed agreement between itself and DSD which indicated that both FAES and DSD agreed to accept the rate and rate design containing the revised COS and rate design components as directed in the CPCN Decision. The executed agreement, which was signed by FAES and the Secretary-Treasurer of the DSD's Board of Education, stated, among other things: "FAES and the SD confirm that the rates and rate design acceptable to the BCUC as set out in Order G-31-12 are also acceptable to both FAES and the SD and are consistent with the existing terms of the Energy System Rate Development Agreement (RDA)."[12]

The BCUC reviewed the filing and, with the exception of the methodology for calculating capitalized overhead and the cost of debt, generally accepted the rate and rate design.[13]

On June 11, 2012, FAES filed a revised rate in its compliance filing to Order G-71-12 (Compliance Filing) containing amendments to the methodology for calculating capitalized overhead and the cost of debt. The schedules contained in the Compliance Filing also included the revised forecast capital expenditures for the TES. The BCUC approved the Market Rate mechanism as well as the COS Rate for Fiscal 2012/13 as recalculated in the Compliance Filing.[14]

1.2.3 F2013/14 and F2014/15 Revenue Requirements and Rate Applications

While the rate being charged to DSD annually commencing in F2012 is the Market Rate, FAES also filed annual COS Rate applications with the BCUC. As outlined in the RDA, the difference between the Annual COS and the annual revenues collected is recorded in the DDA.

On April 3, 2013, FAES applied for approval of the COS Rate for thermal energy services provided to the DSD from July 1, 2013 through June 30, 2014 (F2013/14). FAES indicated at that time that it planned to file a Tax Loss Utilization Plan (TLUP) in 2013 that would allow FAES to recognize certain tax benefits. The filed revenue requirements produced a forecast COS Rate of $0.107/kWh for this period. The BCUC approved the forecast COS Rate, without the use of a TLUP, for F2013/14.[15]

On May 13, 2014, FAES applied for approval of the forecast COS Rate for Fiscal 2014/15, which runs from July 1, 2014 through June 30, 2015. The revenue requirement produced a forecast COS Rate of $0.200/kWh for F2014/15. In response to BCUC information requests (IRs), FAES revised its application and reduced the forecast COS Rate to $0.132/kWh. The rate was further amended to $0.139/kWh in FAES' letter dated July 15, 2015.

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[11] Order C-3-12.
[12] Compliance Filing to Order G-31-12, Attachment 1, p. 1.
[13] Order G-71-12.
[14] Order G-88-12.
[15] Order G-81-13.

The BCUC approved the COS Rate for F2014/15, subject to revisions to the cost of debt rate used by FAES. Furthermore, the BCUC directed FAES to provide a more fulsome explanation for the most recent fiscal year's actual COS compared to the previous year's forecast COS in all future rate applications.[16]

In its letter dated August 8, 2014, FAES filed a recalculated COS Rate of $0.138/kWh based on a revised cost of debt rate in compliance with the adjustments requested by the BCUC.

1.2.4 F2015/16 Revenue Requirements and Rate Application

As with previous years, on April 29, 2015, FAES applied for approval of the annual COS Rate, which FAES forecast to be $0.183/kWh for Fiscal 2015/16 (F2015/16 RRA).

In compliance with Order G-100-14, FAES provided additional details pertaining to the variance between the previous year's forecasted COS and the actual COS recorded. In its discussion detailing the differences, FAES submitted that it had overestimated thermal demand in its previous forecast due to a number of factors and that it was working with DSD to resolve heat pump-related operational issues by actively working to improve the operation of the systems by modifying control sequence, reviewing set points, and monitoring and trending the performance.[17]

Upon review of the F2015/16 RRA, the BCUC issued Order G-146-15A and attached Reasons for Decision and directed FAES to provide further submissions on a number of topics, including:

- A table showing the previously approved forecast revenue requirements, COS Rate, and deferral balance compared to the actuals for each historical fiscal year;
- Whether the definitions contained in the RDA for "District Deferral Account" should mean the cumulative difference between the forecast annual cost of service and forecast revenues or actual revenues;
- Whether it is necessary to amend the RDA; and
- How it intends carrying out the rate-setting mechanism going forward and whether a variance to the original CPCN Decision is necessary.[18]

On November 17, 2015, FAES submitted a compliance filing with the additional requested information and submissions. Regarding the definition of the DDA, FAES submitted the following definitions from section 1.1 of the RDA:

> "District Deferral Account" means the record of the <u>cumulative difference between the Annual Cost of Service and revenues</u>, including a provision for interest at the AFUDC [Allowance for Funds Used During Construction] rate. (Emphasis added by FAES)
>
> "Annual Cost of Service" means FEI's <u>total cost of Services</u> for all of the Buildings in respect of which the Parties have entered into a Energy System Service Agreements at any time during the Term and that have been approved by the BCUC, including,... (Emphasis added by FAES)
>
> "Services" means those services to be provided by FEI to supply Thermal Energy to a Building from an Energy System.

FAES submitted that "as a result of those definitions, the Deferral Account captures the cumulative difference between the actual annual costs and actual annual revenues plus an amount for AFUDC."[19]

[16] Order G-100-14.
[17] F2015/16 RRA, pp. 6-9.
[18] Order G-146-15A.
[19] F2015/16 RRA proceeding, Exhibit B-10, p. 4.

On December 24, 2015, the BCUC approved the forecast COS Rate of $0.185/kWh for Fiscal 2015/16 (F2015/16 RRA Decision).[20] In the F2015/16 RRA Decision, the BCUC found, among other things, that FAES' interpretation of the definition of the DDA contained in the RDA was reasonable and as a result, it renders the BCUC's annual approval of the forecast costs to be "moot." The BCUC further stated that it "urges FAES to apply for a variance and reconsideration amending the requirement to provide annual revenue requirement filings to the [BCUC], until such time that a fundamental change in rate structure or rate methodology exists or if a complaint has been received by the [BCUC]."[21]

On March 31, 2016, as recommended in the F2015/16 RRA Decision, FAES filed an application seeking, among other things, a variance of Orders G-31-12 and G-100-14 regarding the requirement to file annual COS Rate applications for approval with the BCUC. The BCUC approved the request[22] and subsequently, the annual forecast COS Rate and DDA balances for F2016/17 and F2017/18 were provided by FAES to the BCUC and the DSD for informational purposes only.

1.3 Current Regulatory Review Process

Upon receipt of this Application on February 8, 2018, the Panel initiated a public hearing review process, including establishing and subsequently amending a regulatory timetable.[23]

On April 5, 2018, the Panel held a procedural conference. Participants were invited to make submissions on whether other parties beyond FAES and DSD should participate in the proceeding, and, if permitted, to what extent other parties should be allowed to participate, and whether participant funding should be made available to those parties. Participants were also invited to make submissions on the appropriate regulatory process to review the Application (e.g. written hearing, oral hearing, negotiated settlement, etc.), whether DSD or other parties intended to file evidence, whether the BCUC should approve interim rates, and any other procedural matters.

The DSD was the only party to register as an intervener in the proceeding. The Commercial Energy Consumers Association of British Columbia registered as an interested party.

The review process for the Application included BCUC and intervener IRs on the Application, the filing of DSD evidence, BCUC and FAES IRs on DSD's evidence, the filing of rebuttal evidence by FAES, and BCUC and DSD IRs on FAES' rebuttal evidence.

On October 31, 2018, subsequent to the filing of BCUC and DSD IRs on FAES' rebuttal evidence, the BCUC issued a letter requesting submissions from FAES and DSD on the remainder of the regulatory process, including the following:

- Whether there is a need for additional IRs on the evidence already presented on the record;
- Whether an oral hearing is necessary and why; and
- Whether the argument phase should be in written or oral form.

On November 13, 2018 and November 20, 2018, FAES and DSD, respectively, provided submissions on further process, and FAES filed a reply submission on November 23, 2018.

[20] Order G-213-15.
[21] F2015/16 RRA Decision, pp. 1-4.
[22] Order G-53-16.
[23] Orders G-56-18, G-77-18, G-83-18, G-118-18, G-228-18, G-31-19 and G-36-19.

Based on the existing evidentiary record and the parties' submissions, the Panel determined that the evidentiary record was sufficient and directed that the evidentiary record be closed and that the hearing proceed to written arguments.[24] The regulatory timetable was further amended to address DSD's filing of new evidence as part of its final argument and to request additional submissions from FAES and DSD on a potential phase-in of the proposed COS Rate.[25]

On February 26, 2019 and March 5, 2019, DSD and FAES, respectively, filed supplementary final arguments on a potential phase-in of the COS Rate. On March 12, 2019, at the request of the Panel, DSD filed an additional submission clarifying its position on a potential phase-in period. FAES responded to DSD's clarification on March 14, 2019.

1.4 Approach to the Decision

In response to BCUC IR 1.4, DSD submitted that the BCUC must make determinations on the following issues in this proceeding:

1. Whether FAES is contractually permitted to apply to the BCUC for approval to switch DSD from the Market Rate to the COS Rate at this time;
2. If so, whether DSD should be switched from the Market Rate to the COS Rate at this time; and
3. If so, what COS Rate DSD should be required to pay.[26]

Section 2.0 of this Decision addresses the first issue identified by DSD. Section 3.0 of the Decision addresses, in part, issue no. 2, as DSD has requested that the BCUC delay its decision on switching to the COS Rate until after the BCUC has undertaken a full prudency review of the project capital costs.[27] Section 4.0 of the Decision addresses the third issue regarding the amount of the COS Rate and the reasonableness of the Annual Cost of Service. Finally, Section 5.0 of this Decision addresses the timing of a switch to the COS Rate, including whether the COS Rate should be phased in and the effective date of the COS Rate.

In dealing with this Application, the Panel observes that it is being asked to adjudicate the setting of revenue requirements and rates pursuant to the statutory authority granted to it by the UCA. In doing so, the Panel is mindful that it is bound by the provisions of its enabling legislation and the regulatory scheme set out therein. Unlike courts, the BCUC does not have any inherent jurisdiction or the authority to adjudicate breach of contract or similar claims, meritorious or otherwise.

2.0 Request to Switch from the Market Rate to the COS Rate

2.1 The Rate Development Agreement and the Market Rate

On September 26, 2011, FEI and DSD negotiated the ESSAs in support of the provision by FEI of thermal energy services at existing and future sites within the DSD. At the same time, the parties entered into the RDA, under which all the costs of providing service to each of DSD's sites were pooled into a single rate. FEI subsequently assigned the agreements to FAES. According to FAES, "This single, pooled, postage stamp rate recovers the COS that FAES incurs to serve all the buildings."[28] FAES further states "[t]he RDA is a Cost of Service rate design"[29] which "included a transitional market rate with the purpose of smoothing rate fluctuations in the initial years of

[24] Order G-228-18 and Reasons for Decision, Appendix B, p. 6.
[25] Orders G-31-19, G-36-19.
[26] Exhibit C1-8, DSD response to BCUC IR 1.4.
[27] DSD Final Argument, p. 49.
[28] Exhibit B-1, p. 7.
[29] Ibid.

the service."[30] FAES asserts that the parties have agreed contractually from the outset that there would be a switch from the transitional Market Rate to the COS Rate during the 20 year initial term of the RDA.

As noted earlier, by Orders G-31-12, G-71-12 and G-88-12 issued in 2012 following a public review process, the BCUC approved FAES' application for a CPCN and rates for the construction and operation of the thermal energy service to DSD, including the negotiated contracts between FAES and DSD. The validity of those previous orders has not been challenged prior to this proceeding.

Since 2012, FAES has continued to provide service to DSD under the stipulated Market Rate in the RDA. The Panel notes, however, that by Order G-77-18 issued April 12, 2018, FAES is required to maintain the Market Rate as an interim rate effective July 1, 2018 subject to adjustments pending the Panel's decision on this Application.

In assessing whether the Application ought to be granted, the Panel must look first to the four corners of the written agreement between the parties. The Panel notes that Recital C of the RDA stipulates that the "Parties wish to agree on a single rate for Thermal Energy that FEI delivers to the District under each of the Energy System Services Agreements."[31]

In addition, section 1.1 of the RDA explicitly defines the following terms:

> (d) "Annual Cost of Service" means FEI's total cost of Services for all of the Buildings in respect of which the Parties have entered into Energy System Service Agreements at any time during the Term and that have been approved by the BCUC, including:
>
> (i) the return on the Rate Base Value of FEI necessary to provide Service to all of the Buildings in respect of which the Parties have entered into Energy System Service Agreements at any time during the Term and that have been approved by the BCUC, utilizing the capital structure of FEI, the debt financing rate in that capital structure and the benchmark rate of return on equity for utilities in British Columbia plus 50 basis points;
>
> (ii) amortization, depreciation and tax costs;
>
> (iii) direct costs;
>
> (iv) Energy Purchase Costs;
>
> (v) a reasonable amount for overhead allocation and administration;
>
> (vi) the annual amount necessary to recover the SD37 Rate Rider discount provided in the immediately prior Annual Period;
>
> (vii) the annual amount necessary to amortize the District Deferral Account balance, either credit or debit, over the remaining years in the Term or ten (10) years, whichever is longer; and
>
> (viii) any other amount that the BCUC determines that it should include from time to time;[32]
>
> …
>
> (o) "Cost of Service Rate" means the following amount:
>
> ((FACS – EPC) / FTED) + Energy Rate

[30] Exhibit B-1, p. 24.
[31] Exhibit B-1, Appendix E, RDA, Recital C, p. 1.
[32] Exhibit B-1, Appendix E, RDA Section 1.1(d).

where:

“FACS” = the forecast Annual Cost of Service
“EPC” = Energy Purchase Costs; and
“FTED” = the Thermal Energy for the applicable Annual Period;[33]

…

(q) “District Deferral Account” means the record of the cumulative difference between the Annual Cost of Service and revenues, including a provision for interest at the AFUDC rate;[34]

…

(bb) “Index Adjustment” means, at any point in time, the quotient of most recent natural gas index value for British Columbia from Statistics Canada with CANSIM vector number V41692506 divided by 112.0;[35]

…

(cc) “Initial Market Rate” has the meaning given in Schedule B [$0.089 per KWh per 2011/2012 estimates];[36]

…

(ee) “Market Rate” at any point in time means an amount equal to:

Initial Market Rate x Index Adjustment;[37]

…

(ff) “Monthly Charges” means that amount established pursuant to this Agreement that the District is to pay for Thermal Energy deliveries to any Building from an Energy System, being (i) the produce of the Thermal Energy Rate and delivered Thermal Energy, plus (ii) all applicable taxes, for the calendar month immediately prior to the date of invoice;[38]

Of particular importance is the following definition of “Thermal Energy Rate” in Section 1.1(rr) of the RDA:

“Thermal Energy Rate” means the Market Rate until either:

(i) the District notifies FEI in writing that it elects to pay the Cost of Service Rate; or

(ii) FEI receives approval from the BCUC to charge the Cost of Service Rate…

…after which time the Thermal Energy Rate means the Cost of Service Rate and the Market Rate will no longer be available.[39]

Four aspects of this definition of “Thermal Energy Rate” are noteworthy. First, there is no specified time limit for either the giving of notice by DSD of election to pay the COS Rate or the receipt by FAES of BCUC approval to charge the COS Rate, provided that FAES complies with three specified conditions for applying for BCUC approval (which are not in dispute here). This means that in theory at least, the switch from the Market Rate to the COS Rate may occur at any time during the term of the RDA, whether at the DSD’s election or at the direction of the BCUC. Equally plausible, though, is the scenario that neither party triggers the switch from the Market Rate to the COS Rate during the term of the RDA. In other words, the switch, although contemplated, is not required by the RDA. Secondly, the definition necessarily implies that there is a difference between the Market Rate and the COS Rate. If the two rates were identical, there would be no need to switch from one to

[33] Exhibit B-1, Appendix E, RDA Section 1.1(o).
[34] Ibid., Section 1.1(q).
[35] Ibid., Section 1.1(bb).
[36] Ibid., Section 1.1(cc).
[37] Ibid., Section 1.1(ee).
[38] Ibid., Section 1.1(ff).
[39] Ibid., Section 1.1(rr).

the other. Thirdly, as FAES points out in its Application, neither the election by DSD to pay the COS Rate nor FAES' application to charge the COS Rate "is contingent upon the relative position of the MR and the COS Rate."[40] This means that the propriety of any switch does not turn on whether one or the other of the rates is more or less favourable to a counterparty at any point in time, and the consent of the other party is not required. Lastly, the definition makes it clear that the parties intended the Market Rate to remain in place unless and until such time as a switch to the COS Rate occurs either at the election of DSD or the receipt by FAES of BCUC approval to charge the COS Rate.

The current Application arises because the parties dispute both the timing and appropriateness of the implementation of the switch from the Market Rate to the COS Rate pursuant to the RDA. According to DSD, the parties agreed that no switch from the Market Rate to the COS Rate would occur unless and until such time as DSD determines that the switch would be in its best interests.[41] In contrast, FAES asserts that the parties contemplated that the Market Rate would only remain in place as a transitional rate for a period up to five years to allow the project to reach a steady state before the switch would be made.[42]

2.2 Transitional Period

Barring any express specification in the RDA as to the period of time that the Market Rate would remain in place, what were the parties' objective intentions in this regard as gleaned from the entirety of the agreement and the factual matrix surrounding the agreement?[43] As noted above, the RDA does not explicitly refer to the Market Rate as a transitional rate nor does it specify a minimum or maximum period of time that rate may remain in place.

FAES' Position

FAES points to the following as illustrative of the parties' intention that the Market Rate would be transitional rather than indefinite:

- The establishment of the Market Rate is accompanied by the creation and subsequent BCUC approval of the DDA which captures any over/under-recovery of the costs during the period that the Market Rate is in place.[44] The greater the difference between the COS Rate and the revenues and the longer the delay in the switch from the Market Rate to the COS Rate, the more the balance in the DDA will accumulate for subsequent recovery from DSD over the number of years remaining in the initial term of the service after the switch. "Remaining on the MR and avoiding paying the COS will cause the DDA balance to continue to grow."[45]
- "The transitional market rate was not intended to be used for speculation or to delay paying the COS Rate indefinitely," as evidenced by DSD's response to BCUC IR 1.20.1 in the CPCN proceeding. DSD stated that amongst the factors it would consider before triggering an election to switch is "the fact that the market rate is intended to the [sic] transition, not provide a market speculation mechanism" which DSD acknowledged "have been discussed during agreement negotiations and are well understood".[46]
- While "the timing of the switch to COS was left flexible," FAES consistently asserted in the CPCN proceeding that the intention of the Market Rate was to provide a transition period prior to charging the COS Rate within approximately two to five years.[47]

[40] Exhibit B-1, p. 1.
[41] DSD Final Argument, pp. 12-14.
[42] Exhibit B-1, p. 2.
[43] See Sattva Capital Corp. v. Creston Moly Corp., [2014] 2 SCR 633 (SCC).
[44] FAES Final Argument, pp. 15-16.
[45] Ibid., pp. 1, 9, 12.
[46] Exhibit B-1, pp. 9-10; CPCN proceeding, Exhibit C1-2, BCUC IR 1.20.1.
[47] Exhibit B-1, p. 14.

In particular, FAES asserts that the Market Rate "was originally setup to allow a transition period to the COS Rate in recognition of the DSD's need to manage its annual budgetary requirements" and has "the purpose of smoothing rate fluctuations in the initial years of the service." The purpose having been achieved with the result that DSD has enjoyed the benefits of a service that is less than the originally forecast Market Rate, the COS Rate and business as usual costs for five years, it is timely for the switch to occur now in light of the significant balance in the DDA ($3.925 million as of June 30, 2018[48] and estimated to exceed $20 million at the end of the RDA term if a switch does not occur), "which increases future rates for the DSD and risks to FAES."[49] The DSD having enjoyed the benefits of the transitional Market Rate for five years (one-quarter of the 20-year RDA term), the Market Rate "has, at this point, outlived its purpose."[50]

In its final argument, FAES also relies on the following from the CPCN Decision as support for its position that the Market Rate was intended as a transitional rate:

- The BCUC's references in multiple places to the Market Rate as a "transitional rate";
- References to FAES' ability to apply to move the DSD to a COS Rate, and FAES' expectation that the changeover would take place within two to five years;
- The BCUC's statement that DSD has the ultimate responsibility for all costs related to the project and the recognition of the DDA as the recovery mechanism for the costs incurred during the Market Rate period; and
- The BCUC's caution to the parties that remaining on the Market Rate for too long would: (i) have adverse implications for the DSD down the road; and (ii) give rise to intergenerational equity concerns.[51]

In particular, FAES quotes the following passages from the CPCN Application and IR responses:[52]

> As the "market rate" was intended to be transitional in nature, and was not intended as a mechanism for the customer to delay paying the cost of service over the longer term, the RDA confers upon FEI the right to apply to the BCUC for approval to switch the thermal energy rate from the market rate to the cost of service rate at any time.[53]
>
> …
>
> Although there is no set time by which the SD must switch from the transitional "market rate" to the cost of service rate, the variance between the "market rate" and the true cost of service will be captured in the SD37 Deferral Account, and either recovered from, or returned to, the customer. It is not likely to be in the customer's interest to remain on the "market rate" if it means accumulating significant balances that must be recovered down the road.[54]
>
> …
>
> In the case of the SD, the cost of service rate is the product of negotiation between FEI and the SD and the terms are mutually acceptable. It ultimately results in the cost of providing service being recovered from the customer over the full fixed year term. There is modification to some degree, as it includes a transition mechanism to ensure that in the short term the rate reflects the customer's energy costs in the absence of the project.[55]
>
> …

[48] Exhibit B-1-1, Appendix A, p. 3.
[49] Exhibit B-1, pp. 17, 22, 24.
[50] FAES Final Argument, p. 21.
[51] Ibid., pp. 21-22; CPCN Decision, pp. 51-53
[52] FAES Final Argument, p. 45.
[53] CPCN Application, Exhibit B-1, p. 45.
[54] CPCN Application, Exhibit B-1, p. 44.
[55] CPCN Application, Exhibit B-10, BCUC IR 2.2.2.

> A transition within 2 to 5 years is expected to be reasonable. However, since the purpose of the market rate is to provide a smooth transition from market rates to cost of service and both the market rate and cost of service rate are subject to forecast variations, the agreement with the SD maintains timing flexibility for the switch.[56]

FAES further points to the following endorsement from DSD in the compliance filing to the CPCN Decision[57] in support of its position:

> The Secretary-Treasurer of the DSD had signed the 2012 Rate Design Compliance Filing, confirming that the DSD had received two reports and agreed that the content was consistent with the DSD's intent. Those reports had reiterated that the MR was a transitional mechanism, and had contemplated the recovery of deferred costs from the DSD during the RDA term.[58]

FAES goes on to note that in the F2015/16 RRA proceeding, DSD's final submissions alluded to the five-year transition in expressing its concern about the BCUC switching to the COS Rate unilaterally in 2015:[59]

> As the Commission also noted in the CPCN Decision, FEI originally anticipated that DSD would elect to switch from the market rate to the cost of service rate within two-to-five years. Importantly, DSD notes that period that [sic] has not yet elapsed. [60]

DSD's Position

As FAES noted in its final argument, DSD's position on the timing of the proposed switch from the Market Rate to the COS Rate is summarized in three points in DSD's letter included with the Application:

1. DSD is not contractually required to switch unless and until DSD determines that such an election would be in its own best interest;
2. FAES may only apply for BCUC approval of the switch if there are clear and demonstrable benefits to DSD in doing so; and
3. If DSD does not switch from the Market Rate to the COS Rate during the RDA term, and elects not to renew the RDA, FAES shareholders will be solely responsible for any and all amounts accrued in the DDA.[61]

DSD further disputes FAES' assertion that the Market Rate was intended as a transitional rate.

In support of its position, DSD relies on the affidavit evidence of its witness, Frank Geyer (Geyer), who adduced email correspondence from 2011 between himself and FEI's Business Development Manager, Grant Bierlmeier (Bierlmeier), relating to the negotiations of the RDA and the ESSAs leading up to the filing of the CPCN Application. According to Geyer:

> …at no time during these discussions did Mr. Bierlmeier or any other FEI representative state that there would be a 3 to 5 year transition period for switching to the COS rate. To the contrary, Mr. Bierlmeier repeatedly and expressly stated that DSD could continue to pay the Market Rate for so long as it was in DSD's best interests to do so.[62]
>
> …

[56] CPCN Application, Exhibit B-3, BCUC IR 1.38.3.
[57] Compliance Filing to Order G-31-12, Attachment 1, p. 1.
[58] FAES Final Argument, p. 54.
[59] FAES Final Argument, p. 70.
[60] Exhibit C1-6, DSD Evidence, Affidavit #1 of Frank Geyer, Exhibit GG, p. 388.
[61] Exhibit B-1, Appendix C; FAES Final Argument, p. 40.
[62] Exhibit C1-6, DSD Evidence, Affidavit #1 of Frank Geyer, p. 11.

> …one of the objects of the contract was to create a rate structure whereby DSD would only be required to switch from the market rate…to the cost-of-service rate…if it was in DSD's best interests to do so.[63]
>
> …
>
> At all material times during the above-noted email exchanges, I understood that FAES could only apply to switch DSD from the Market Rate to the COS Rate if it was in DSD's best interests (including its best financial interests) to switch.[64]

The Panel notes that in an email dated September 15, 2011 from Bierlmeier to Geyer explaining the reason for including the clause enabling FAES to apply for BCUC approval of the switch, Bierlmeier states:

> However, while I trust you to be reasonable Frank, since I know you understand this deal, I don't know what mindset will prevail at the District in 10 or 15 years from now. As of now, we all want to get to Cost of Service, but you need proof that it will be beneficial, which is what the market rate gives you so that you can get some comfort that COS is going to be reasonable before switching. We would go straight to COS, but this way, with the market rate, you have the chance to watch and ensure that the costs are in line with expectations first. What worries me is in 10 or 15 years from now, if the District is still on the market rate, the people administering the contract may not know what our intent was today and may not elect or agree to go to COS rates, even if there are good reasons to do it.[65]

Assuming that the Panel finds that this pre-contractual email correspondence is relevant and admissible in determining the parties' intentions (which the Panel does not for the reasons set out below), Bierlmeier appears to entertain at that point at least the possibility that the Market Rate may remain in place for as long as 10 to 15 years, even if there are good reasons for switching to a COS Rate. Taken in isolation, this may lend some credence to DSD's belief that the Market Rate may extend beyond five years. However, in the Panel's view it is equally plausible that this was intended as pure speculation on the part of Bierlmeier in posing an unlikely hypothetical scenario.

In addition to the pre-contractual discussions, DSD also alleges that certain collateral representations made by FAES following the CPCN Decision support DSD's interpretation. In his affidavit evidence, Geyer cites correspondence from 2014 and 2015, his handwritten notes and FAES' evidence filed in the F2015/16 RRA as support for an allegation that FAES had agreed to give DSD a veto over FAES' ability to apply to the BCUC.[66]

Panel Determination

As the parties to the RDA clearly differ in their assessment of the timing and circumstances that would accompany the switch from the Market Rate to the COS Rate, the Panel must determine which is the correct interpretation having regard to the specific nature and wording of the agreement.

The Panel agrees with FAES' submission "that this proceeding, at its core, involves interpreting a written agreement between sophisticated parties that were represented by legal counsel."[67] The Panel notes that counsel for DSD in this proceeding also represented DSD in the negotiations and drafting of the agreements between the parties, albeit not in the CPCN Application, despite FAES having advised DSD that it could not be legally represented by FAES' counsel in that proceeding.

[63] Exhibit C1-6, DSD Evidence, Affidavit #1 of Frank Geyer, p. 8.
[64] Ibid., p. 10.
[65] Ibid.
[66] Ibid., pp. 19-28.
[67] Exhibit B-1, p. 4.

Section 11.8 of the RDA is unequivocal that the written agreement contains the entire agreement between the parties and excludes any implied terms or understandings:

> This Agreement contains the whole agreement between the Parties in respect of the subject matter hereof and there are no terms, conditions or collateral agreements express, implied or statutory other than as expressly set forth in this Agreement and this Agreement supersedes all of the terms of any written or oral agreement or understanding between the Parties, including without limitation the letter of intent between the Parties dated February 7, 2011.[68]

As the Panel has already observed, the definition of the Thermal Energy Rate contemplates but does not dictate a switch, nor does it set a maximum or minimum time limit for the switch to occur during the term of the RDA. Furthermore, should one party desire to invoke the switch, the consent of the other party is not required. In this regard, the Panel rejects the DSD's contention that FAES agreed to give DSD a veto over FAES' ability to apply to the BCUC. This interpretation is simply not supported by the language in the RDA or any of the evidence adduced by Geyer. Absent other constraints, each party is free to act according to its own best interests, including financial interests, in determining the optimal time to make the switch pursuant to the RDA.

The Panel notes that the RDA is more than an ordinary commercial contract. The RDA is also an approved rate tariff for the provision of a regulated service under the UCA. This means that the contract must be interpreted in a manner consistent with similar contracts for regulated services, established regulatory principles and the statutory scheme created for the efficient regulation of public utilities.

Under section 60 of the UCA, the BCUC must set rates that are not unjust or unreasonable. Section 61 of the UCA requires that terms and conditions of utility service be in writing and be specified in rate schedules filed with the BCUC:

> 61 (1) A public utility must file with the BCUC, under rules the BCUC specifies and within the time and in the form required by the BCUC, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.
>
> (2) A schedule filed under subsection (1) must not be rescinded or amended without the BCUC's consent.
>
> (3) The rates in schedules as filed and as amended in accordance with this Act and the regulations are the only lawful, enforceable and collectable rates of the public utility filing them, and no other rate may be collected, charged or enforced.

Under section 63 of the UCA, a public utility is prohibited from charging compensation for a regulated service other than that specified in the applicable rate schedule:

> 63 A public utility must not, without the consent of the BCUC, directly or indirectly, in any way charge, demand, collect or receive from any person for a regulated service provided by it, or to be provided by it, compensation that is greater than, less than or other than that specified in the subsisting schedules of the utility applicable to that service and filed under this Act.

The parties do not dispute the fact that the RDA has been previously approved by the BCUC as just and reasonable, or that the RDA is a COS Rate design with a specified initial Market Rate. However, the RDA leaves open the question of the timing of the switch and the annual determination of the COS Rate. The Panel agrees

[68] Exhibit B-1, Appendix E, RDA, Section 11.8.

with FAES that the BCUC's determinations on both of these matters must meet the "just and reasonable" standard, having regard to the principles of COS regulation that underlie the RDA:

> Section 59(5) of the UCA defines what is unjust or unreasonable and embodies the regulatory compact… In basic terms, the regulatory compact ensures that the public utility has a reasonable opportunity to recover its prudently incurred costs and earn a fair return on its investment, while ensuring that customer rates are not set to recover excessive profits for the nature and quality of the service provided.[69]

In the Supreme Court of Canada's decision in *Atco Gas & Pipelines Ltd. v. City of Calgary*, the majority emphasized that utilities are businesses whose shareholders are entitled to expect benefits from the rates charged for regulated services:[70]

> These goals have resulted in an economic and social arrangement dubbed the "regulatory compact", which ensures that all customers have access to the utility at a fair price – nothing more… Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated.
>
> Therefore, when interpreting the broad powers of the Board, one cannot ignore this well-balanced regulatory arrangement which serves as a backdrop for contextual interpretation. The object of the statutes is to protect both the customer and the investor.

Having reviewed the provisions of the RDA, the Panel agrees with FAES' contention that the parties have specified for the DSD project a regulated capital structure (debt/equity ratio) and return on equity to enable FAES the opportunity to earn a fair return on the cost of invested capital, commonly referred to as the Fair Return Standard, which return has been approved by the BCUC. The Panel further agrees that once approved, fundamental to the regulatory compact is the requirement that FAES be given a reasonable opportunity to earn that allowed return. Any action that forecloses FAES from ever pursuing that opportunity would run counter to the regulatory compact and the BCUC's duty to approve rates that will provide the utility a reasonable opportunity to earn a fair return on invested capital, which duty has been described by the Supreme Court of Canada as "absolute".[71]

In order for the utility to be able to have an opportunity to earn its allowed return under cost of service regulation, rates must be set to recover:

- The forecast prudently incurred costs of providing service (which include operating expenses, annual depreciation expense that covers a portion of the prudently incurred invested capital, taxes and debt financing costs); plus
- The allowed ROE (being 50 basis points above the benchmark ROE in this case).[72]

In the Panel's view, rates that are set at a level below the forecast needed to meet these two requirements in any given year, without the ability to recover the shortfall later, run counter to the Fair Return Standard and would not be just and reasonable within the meaning of the UCA.

[69] FAES Final Argument, pp. 9-10.
[70] FAES Final Argument, Book of Authorities, Atco Gas & Pipelines Ltd. v. Alberta (Energy Utilities Board) 2006 SCC 4 (CanLII) at 140-225, para. 63-64.
[71] BCUC Generic Cost of Capital (Stage 1, 2013), Order G 75-13 and Decision dated May 10, 2013, pp. 11-12; BC Electric Railway Co. Ltd. v. The Public Utilities Commission of BC, [1960] SCR 837 at pp. 848-849.
[72] FAES Final Argument, p. 14; CPCN Decision, p. 4; Order G-71-12.

The evidence shows that in the first five years of service under the Market Rate, the DSD has been paying far below the "cost based rates" contemplated by the BCUC in the Generic Cost of Service Capital (Stage 1) Decision, with the result that the unrecovered portions of FAES' cost of providing service are accumulating in the DDA to the amount of $3.925 million as of June 30, 2018, and are anticipated to grow to more than $20 million by the end of the RDA term. The impact of the under-recovery of the Annual Cost of Service means that there is a negative ROE (i.e. loss) in that year, with the amount of the under-recovery being added to the DDA for future recovery. The only way that FAES can recover that loss from DSD is by switching the DSD from the Market Rate to the COS Rate over the remaining term of the RDA and thereby reducing the build-up of the DDA, which FAES is contractually entitled to do provided that it receives BCUC approval to do so.

In light of the regulatory compact and the lack of specified constraints on the timing of any application for BCUC approval of a switch from the Market Rate to the COS Rate, the Panel finds it is just and reasonable to approve the Application by giving effect to FAES' right to trigger the switch at this time.

As for the evidence offered by Geyer, the Panel rejects that evidence on the basis that it is irrelevant to the determination of the timing of the switch in light of the language in section 1.1(rr) and the Entire Agreement clause in section 11.8 of the RDA. The Panel accepts that the Market Rate was intended by the parties to be a temporary rate that would remain in place pending DSD's election to switch to the COS Rate or FAES' receipt of BCUC approval to do so. The Panel is particularly cognizant that based on the history and costs of the service to date, the impact of an indefinite delay in the implementation of a switch from the current Market Rate to the COS Rate would effectively preclude FAES from ever having the opportunity to earn its allowed ROE as approved by the BCUC. For the Panel to permit DSD to remain indefinitely on the Market Rate would be contrary to the regulatory compact which forms the basis for the provision of regulated utility services and which is reflected in the structure of the BCUC-approved RDA.

Additionally, the Panel notes that as early as the time of the CPCN Application in 2011, DSD was aware of FAES' view that the Market Rate should remain in place only for two to five years, after which there could be a switch to the COS Rate. Furthermore, DSD itself implicitly accepted that the five-year period should be upheld during the F2015/16 RRA proceeding when it urged the BCUC not to unilaterally order a switch on the basis that five years had not elapsed at that time.

It is perhaps regrettable that neither party sought to amend the RDA to clarify their respective understanding by specifying a fixed period of time during which the Market Rate must remain in place. The Panel observes that an upper limit of 10 years is arguably supportable according to section 1(d)(vii) of the RDA, which provides that the Annual Cost of Service to be recovered through the COS Rate includes, "the annual amount necessary to amortize the District Deferral Account balance either credit or debit, over the remaining years in the Term or ten (10) years, whichever is longer." However, the Panel is of the view that this ten-year reference pertains only to the potential length of the amortization period for the DDA, as opposed to the length of the intended transitional period.

Furthermore, based on a review of all of the evidence and for the reasons to be discussed later on in this Decision relating to a proposal for phasing in the COS Rate, the Panel is not persuaded that it would be in either FAES' or DSD's best interest for the switch to be further delayed beyond the aforementioned potential phase-in, and declines to do so.

2.3 Collateral Representations

DSD raises the issue of collateral representations in support of its argument that the BCUC should not approve the Application. In essence, DSD argues that the BCUC has, in 2012, approved an implied term of service that precludes a switch to the COS Rate in certain circumstances. In response to BCUC IR 1.2 seeking DSD's view of the BCUC's jurisdiction to adjudicate on allegations of misrepresentation, DSD offered the following response:

> DSD maintains that the Commission has the jurisdiction to consider evidence of certain representations FAES has made to DSD for the purpose of determining the terms and conditions of the RDA and the ESSAs, for the purpose of determining whether FAES is legally precluded from bringing the current application, and for the purpose of exercising the Commission's rate-making powers under the *Utilities Commission Act*.[73]

Panel Determination

As already noted, section 1.1(rr) of the RDA does not specify the timing for the switch to the COS Rate. In the absence of that, other provisions of the RDA may provide some basis for the Panel to determine what the parties had objectively intended to be the timing of the switch. If there is no such determinative evidence, the Panel must give effect to the words of the relevant provision governing the switch, which allows it to occur at any time during the term of the RDA. The issue then is whether it would be appropriate for the Panel to admit into evidence alleged collateral representations in support of DSD's argument that they legally preclude FAES from bringing the current Application.

In the Panel's view, the parties are bound by the Entire Agreement clause in section 11.8 of the RDA which precludes all other oral or written collateral agreements and terms. The Panel notes that the RDA was negotiated and entered into voluntarily by two sophisticated parties, each represented by legal counsel. The only amendment that is binding upon the parties is the subsequent written amendment dated October 31, 2011. To allow evidence of collateral representations to modify the written terms of the agreement would fly in the face of section 11.8 of the RDA. However, even if the Panel were inclined (which it is not) to accept Geyer's affidavit evidence of the collateral representations as relevant and admissible in this proceeding, that evidence does not go so far as to suggest any of the following:

- Any promise on the part of FAES that it would never exercise the right to apply for a switch to the COS Rate during the term of the RDA without DSD's consent;
- Any promise on the part of FAES that the rate charged to DSD under the RDA would always be lower than the COS Rate or the business as usual rate;
- Any promise on the part of FAES that DSD's rates would always be subsidized by FAES and its shareholders; or
- Any agreement on the part of FAES to give DSD a veto over the establishment of the applicable rate for the service – as noted by FAES, sections 58(1) and 37 of the UCA give a public utility the statutory right to apply at any time to amend an approved rate schedule.

As for Geyer's contention that FAES led DSD to believe that a switch in rates would not occur unless and until it was in DSD's own financial interests to do so, that proposition is simply untenable in light of the fact that section 1.1(rr) of the RDA contemplates that FAES may act on its own accord during the RDA term to trigger a switch without any requirement for consent from DSD. **The Panel, based on a review of all of the relevant evidence finds as follows:**

- **The RDA is based on a COS Rate design under which FAES anticipated it would be able to recover its cost of service, including an allowed ROE during the term of the RDA;**
- **At the time they entered into the RDA, the parties expressly agreed to be bound by the Market Rate for an unspecified period of time;**

[73] Exhibit C1-8, DSD response to BCUC IR 1.2.

- **FAES fully anticipated that it would be able to recover any difference between the COS Rate and the annual revenues from the service by accounting for the annual differences in the DDA and recovering the balance in the DDA over the remaining term of the RDA;**
- **By the time of the CPCN Application, DSD was aware of and did not challenge FAES' expectation that the Market Rate would be in place for a period of at least two to five years, during which FAES did not anticipate applying for a switch to the COS Rate;**
- **What would happen beyond that five-year period would depend on whether one or the other of the parties triggers the switch from the Market Rate to the COS Rate and the timing of that switch; and**
- **The DSD has enjoyed a rate for the thermal energy service which has been lower than the COS Rate, the forecast Market Rate and the business as usual rate.**

While DSD has no doubt grown accustomed to the benefits of that reduced rate, in the view of the Panel, nothing in Geyer's evidence provides support that this amounts to a guarantee from FAES that those benefits to DSD would continue for the remainder of the RDA term or that would legally preclude FAES from bringing forward this Application at this time.

Accordingly, in light of all of the above, the Panel rejects DSD's argument that the alleged collateral representations ought to be interpreted in such a way as to disallow FAES the remedy sought.

2.4 Promissory Estoppel

DSD also raised the alternative argument of promissory estoppel as a basis for the BCUC denying the relief FAES is seeking in this Application.

DSD's Position

DSD acknowledges that the BCUC ultimately has the jurisdiction to determine whether to switch the DSD from the Market Rate to the COS Rate. Accordingly, DSD is prepared to proceed on the basis that FAES may apply to switch the DSD from the Market Rate to the COS Rate. However, DSD maintains that the BCUC should decline to grant such relief on the basis the alleged representations (referred to above) are relevant to the determination of whether the proposed COS Rate is just and reasonable, and effectively operate as an estoppel that the BCUC should find collectively precludes FAES from being granted the relief that it seeks.[74]

DSD submits promissory estoppel has five elements:

(a) the parties have a legal relationship (most commonly in the form of a contract);

(b) the promisor has, by words or conduct, made a promise or an assurance which was intended to affect the parties' legal relationship and be acted on by the promise;

(c) the promisee relied on the representations and acted on it or in some way changed position;

(d) the promisee acted upon the promise to its detriment; and

(e) the promisee acted equitably.[75]

DSD refers to case law and submits that:

- Not all of the elements need to be present in applying promissory estoppel; and

[74] DSD Final Argument, p. 38.
[75] Ibid.

- In the context of a labour arbitration, an arbitrator has a broad mandate in whether to adapt and apply equitable and common law principles (such as promissory estoppel), in a manner that is consistent with the objectives and purposes of the applicable statutory scheme, the principles of labour relations, the nature of the collective bargaining process, and the factual matrix of the grievance.[76]

DSD submits that it has established the elements of promissory estoppel in this Application. In particular, it states that it has established the following:

- DSD and FEI/FAES have a legal relationship;
- FEI/FAES represented to DSD that it expected the COS Rate to drop below the Market Rate and that the DSD would not be switched to the COS Rate until the COS Rate was "in line with expectations";
- DSD relied on these representations and acted on these representations by agreeing to the rate and rate design proposed by FAES in the CPCN Application proceedings; and
- DSD acted equitably.[77]

Accordingly, in furtherance of the BCUC's statutory mandate under sections 59-60 of the UCA, applied in light of the factual matrix in which the RDA was negotiated, executed, and approved, DSD submits the BCUC should find that FAES is estopped from obtaining an order switching to the COS Rate until it is competitive with the Market Rate and provides benefits to the DSD in the form of low and/or less volatile rates, as the parties originally contemplated. DSD maintains any other outcome would not be just and reasonable for the purposes of section 59 of the UCA.[78]

FAES' Position

FAES submits the DSD's estoppel argument is not applicable in the regulatory context of the BCUC's statutory mandate in setting public utility rates for the following reasons:

- DSD has failed to identify any case law or regulatory decision which provides authority for the proposition that promissory estoppel is, in these circumstances, a proper consideration for the BCUC in exercising its authority to set rates under the applicable provisions of the UCA. FAES argues that this is because promissory estoppel is a legal principle that, by definition, exists outside of express contractual terms. The estoppel alleged by the DSD is collateral to the RDA and is fundamentally at odds with requirements in the UCA that rate schedules must be in writing, approved by the BCUC and avoid any undue discrimination or preference that would result from departing from the approved terms.
- None of the case law cited by DSD involved an agreement with an Entire Agreement clause, thereby leaving unexplained why it would be reasonable for a sophisticated party with experienced counsel to rely on alleged prior representations in circumstances where it had previously expressly agreed that any prior representations would not form part of the RDA.[79]

Panel Determination

In support of its position that the principle of equitable estoppel applies in this Application, DSD refers to a Supreme Court of Canada case which deals with the role of an arbitrator in the context of labour relations.[80] However, the case makes clear that a labour arbitrator in deciding whether to adapt a legal principle such as promissory estoppel must do so in the context of the applicable statutory scheme and the factual matrix.

[76] DSD Final Argument, pp. 38-39.
[77] Ibid., p. 39.
[78] Ibid.
[79] FAES Reply Argument, pp. 11-12.
[80] DSD Final Argument, pp. 38-39.

DSD has not cited any case involving the applicability of promissory estoppel in the context of the statutory role of the BCUC in determining public utility rates under the UCA or in the context of the regulatory compact.

In contrast, FAES has cited decisions of: (i) the Supreme Court of Canada; (ii) the BC Court of Appeal; and (iii) the BCUC, all of which stand for the proposition that the obligation to provide a utility an opportunity to earn its allowed return is absolute. The DSD has made no attempt to distinguish those decisions. Nor has the DSD disputed the fact that remaining on the Market Rate would make it impossible for FAES to ever earn its return on equity as approved by the BCUC and would likely preclude recovery of its invested capital as well.[81]

In the Panel's view, the role of the BCUC in setting rates under the UCA cannot be equated with the role of a labour arbitrator. It is at odds with the statutory scheme in the UCA that requires rate schedules to be in writing and specifically approved by the BCUC. Further, it is at odds with the Entire Agreement clause of the RDA which expressly provides that any prior representations would not form part of the RDA.

In reaching this determination, the Panel has also taken into account its earlier findings in connection with DSD's allegations regarding collateral representations.

Accordingly, in light of all of the above, the Panel rejects DSD's argument that it has established an alleged promissory estoppel which would preclude the BCUC from granting FAES the remedy sought.

3.0 System Design, Operational Efficiency and Prudency

DSD argues that if the BCUC does not dismiss FAES' application to switch to the COS Rate, the BCUC should delay its decision regarding switching to the COS Rate until after a "full prudency review" of the project capital costs has been undertaken.[82] DSD's request for a prudency review is based, in part, on the fact that the actual capital costs incurred by FAES were higher than what was forecast in the CPCN Application and that the GHG emissions reductions are lower than expected.[83]

As the Panel has previously determined that FAES is contractually permitted to apply to the BCUC for approval to switch from the Market Rate to the COS Rate, the Panel will now address DSD's request for a prudency review of the project capital costs and its issues regarding system design and operational efficiency.

3.1 Background and Description of the Capital Assets

The forecast capital cost of the project, as provided in the compliance filing to Order G-71-12 (Compliance Filing), was $6,624,000.[84] This amount excludes the CIAC from DSD of $1,357,000, sustainment capital expenditures and AFUDC.

FAES provided the following comparison between the forecast capital cost of $6,624,000 and the actual capital cost of $8,099,000.[85]

[81] FAES Reply Argument, pp. 12-13.
[82] DSD Final Argument, p. 59.
[83] Ibid., p. 56.
[84] Exhibit B-4, Attachment to BCUC IR 7.1, Schedule 8.
[85] Exhibit B-3, DSD IR 5.1.

Table 1 – Actual Capital Cost Compared to Compliance Filing (in $ thousands)

Line	Particulars	G-71-12	Actual	Variance
1	Capital Spending 2012 Onwards			
2	Mechanical Room Piping	-	1,643	1,643
3	Pumps	1,816	1,652	(164)
4	Boilers	652	544	(108)
5	Structures	-	120	120
6	Intrasystem Piping	-	1,161	1,161
7	Loop Field (Ground Source Heat Exchanger)	4,157	2,044	(2,113)
8	Meter	-	935	935
9	Sustainment Capital	201	-	(201)
10	Total Capital Spending 2012 Onwards	6,826	8,099	1,273
11				
12	AFUDC	64	-	(64)
13	Total Annual Capital Spending and AFUDC	6,890	8,099	1,209
14				
15	Contributions in Aid of Construction	(1,357)	(1,212)	145
16	Net Annual Project Costs- Capital	5,533	6,887	1,354

FAES explains that the key driver for the higher capital costs was thermal metering, shown as "Meter" in the above table. FAES states that while costs related to thermal metering were originally included in the Loop Field cost, they were underestimated. FAES submits that the original capital cost estimates were consistent with AACE Class 3 estimates as required by the BCUC's CPCN Guidelines and that the total variance between forecast and actual capital costs is within the accuracy range of AACE Class 3. The AACE Class 3 characteristics are outlined in the following table:[86]

Table 2 – AACE Class 3 Characteristics

	Primary Characteristic	Secondary Characteristic		
Estimate Class	**Maturity Level of Project Definition Deliverables** Expressed as a % of complete definition	**End Usage** Typical purpose of estimate	**Methodology** Typical estimating method	**Expected Accuracy Range** Typical variation in low(L), and high(H) ranges[(a)]
Class 3	10% to 40%	Funding Authorization	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H:+10% to +30%

(a) The state of technology, availability of applicable reference cost data and many other risks affect the range markedly. The +/- Values represent typical percentage variation of actual costs with the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

In response to DSD IR 2.4, FAES explained that the CPCN Application contemplated FAES owning energy systems for 19 sites including the air source heat pumps at South Delta Secondary. However, in July of 2013, FAES and DSD decided to include two additional natural gas boiler sites (Devon Gardens and Sunshine Hills) in exchange

[86] Exhibit B-3, DSD IR 5.1.

for DSD taking ownership of the air source heat pumps at South Delta Secondary. FAES submits that this alteration of scope was done at the request of DSD.[87]

3.2 Natural Gas Usage and System Optimization

As shown in Table 3 below, the actual natural gas usage for the first six years of the RDA term (excluding the initial year) has been significantly higher than forecast, while the actual electricity usage has been significantly lower than forecast.

Table 3 – Forecast vs Actual Natural Gas and Electricity Usage

Fiscal Year	Forecast Electricity[88] (MWh)	Actual Electricity[89] (MWh)	Forecast Natural Gas[90] (GJ)	Actual Natural Gas[91] (GJ)
2012/13	377	3	5,803	1,887
2013/14	2,376	335	12,995	25,593
2014/15	3,095	287	13,641	22,812
2015/16	3,095	233	13,641	27,205
2016/17	3,095	359	13,641	32,905
2017/18	3,095	309	13,641	32,154

In the F2015/16 RRA proceeding, FAES was asked to describe the factors contributing to the significant increase in the forecast natural gas consumption. FAES responded as follows:

> The original forecast for natural gas consumption was based on engineering assessment and assumptions regarding anticipated seasonal efficiencies of the retrofitted systems. The current forecast for natural gas consumption is based on the actual performance. In the past two years, much of the thermal energy was supplied with the use of natural gas due to various operational issues, which resulted in higher than anticipated use of natural gas. The ongoing continuous optimization of the thermal energy systems is aimed at increasing the utilization of the heat pumps during the early Fall and late Spring. These changes should result in a lower consumption of natural gas.[92]

In the current proceeding, FAES was asked to explain why, given its statements regarding continuous optimization of the thermal energy systems, the actual natural gas costs have only minimally decreased since F2015/16. FAES responded that it expects that natural gas consumption and costs will stabilize at current amounts and that the optimization process, which focused on FAES-owned equipment, is unlikely to result in a further reduction in gas consumption and shift towards electricity without DSD making changes to its distribution system or operating strategy, such as the level and fluctuation of temperature set points due to occupancy.[93]

FAES expects that in order to further improve the efficiency, changes would be necessary to DSD's configuration of the building distribution systems in order to remove "bottlenecks", meaning that in order to reach the full potential of any heat pump-based system, changes must be made to the distribution system and its operations

[87] Exhibit B-3, DSD IR 2.4.
[88] Exhibit B-4, BCUC IR 7.1, Schedule 3.
[89] Exhibit B-1-1, Appendix A, Schedule 4.
[90] Exhibit B-4, BCUC IR 7.1, Schedule 2.
[91] Exhibit B-1-1, Appendix A, Schedule 3.
[92] F2015/16 RRA proceeding, Exhibit B-4, BCUC IR 1.5.1.
[93] Exhibit B-4, BCUC IR 8.3.

to allow the heat pumps to run more often. Without such changes, FAES expects that the system efficiency as a whole will continue to trend in the low to mid 70 percent range.[94]

FAES submitted that in 2016 DSD engaged Rocky Point Engineering Ltd. (RPE) to carry out a design/commissioning review of the central plant of three schools which appeared to be facing operational issues: North Delta Secondary, Delview Secondary and South Park Elementary. FAES and Johnson Controls International (JCI) reviewed RPE's recommendations regarding the operation of the central plant and either completed or investigated the recommendations. FAES then engaged JCI to perform a comprehensive review of the Delview Secondary central plant and the distribution system owned by DSD. Recommendations were made by JCI in its report issued in March 2017 (2017 JCI Report) to improve comfort and performance, including changes and repairs to the central plant and to the maintenance of the distribution system.[95]

FAES submitted that while it implemented each of JCI's recommendations related to the central plant, the findings regarding DSD's distribution system emphasized that "DSD providing timely maintenance to the distribution system will have a significant impact on the central plant's ability to deliver the thermal energy." The issues identified related to the distribution system included replacement of filters, cleanup of coils, covered vents and use of an automation system to command the equipment.[96]

3.3 DSD Evidence and Arguments

DSD introduced in evidence an affidavit from Donald Poole (Poole), a lay witness, relating to the design of the TES installed in DSD schools. However, in response to BCUC IR 2.1, DSD admitted:

> In his capacity as a lay witness, Mr. Poole has not commented on whether the thermal energy system is unsuitable and/or not performing to specifications as approved in the CPCN. However, DSD maintains that FAES is in breach of certain ESSAs approved in the CPCN, and that the evidence of Mr. Poole is germane to this issue.[97]

In his affidavit, Poole explains that around May 9, 2012, Geo-Energie Inc. (Geo-Energie) submitted an engineering proposal to Johnson Controls L.P. (JCLP) for the provision of engineering services regarding the design, construction and installation of geothermal heat pump systems for the DSD project, and that a portion of the work would be undertaken by Geo-Energie's local sub-consultants Poole and Associates Mechanical Engineering Ltd., Altum Engineering and JDQ Engineering, under Geo-Energie's supervision.[98]

Poole submits that around May 25, 2012, he sent an email requesting information to evaluate DSD's existing buildings for suitability for connection to geothermal heat pump systems. Poole stated the following:

> At that point, I was very concerned about the operating parameters of DSD's existing terminal equipment. As a result of my past experience, I knew that the potential for energy saving is very small when a low temperature heat pump is used to supply energy (heat, in this case) to a building that has terminal equipment that is designed for high temperature.[99]

Poole further submits that around May 29, 2012, he toured the nine DSD buildings that had been selected by JCLP for connection to geothermal heat pump systems along with Geo-Energie and two representatives from DSD. During the tour, Poole states that he advised Geo-Energie that he was "concerned that the Project did not include any upgrades to existing terminal equipment outside the

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[94] Exhibit B-4, BCUC IR 8.5.
[95] Exhibit B-4, BCUC IR 9.4.
[96] Ibid.
[97] Exhibit C1-8, DSD response to BCUC IR 2.1.
[98] Exhibit C1-6, Testimony of Donald Poole, p. 2.
[99] Ibid., p. 3.

DSD's mechanical room, nor were there any plans to employ any high temperature heat pump systems which would operate efficiently with DSD's high temperature terminal equipment."[100]

Poole states that after the tour he wrote a series of emails to Geo-Energie and that Geo-Energie responded as follows:

a. The role of Geo-Energie and its sub-consultants in the project was solely to implement the geothermal heat pump systems within the mechanical room. Geo-Energie and its sub-consultants would not address any concerns regarding DSD's terminal equipment outside the mechanical room.

b. JCLP had already selected the DSD buildings that would be connected to geothermal heat pump systems.

c. JCLP had already determined that the low temperature geothermal heat pump systems would provide enough heat to satisfy the energy targets without any upgrades or changes to the terminal equipment in DSD's buildings.[101]

DSD also submitted evidence from MCW Consultants Inc. (MCW), noting that MCW has not provided an opinion on whether the TES is performing to the specifications approved in the CPCN Application. Instead, DSD submits that MCW has "opined on the standard industry practice that a reasonable thermal energy system provider would have followed when designing a thermal energy system for the particular schools discussed in the MCW report."[102] According to DSD, this evidence supports a finding of breach of specified sections of the ESSAs, thereby disentitling FAES from recovery of a portion of the capital costs.

In its evidence, MCW states it examined three of the applicable schools: Delview Secondary, Neilson Grove Elementary and Richardson Elementary. MCW asserts that the natural gas savings anticipated in the CPCN Application using a combination of high efficiency boilers and heat pumps is "very aggressive and relies heavily on the usage of the heat pump system to reduce gas consumption."[103]

MCW further explains that the types of heat pumps used by FAES in the aforementioned three schools are considered to be "low water temperature" units. MCW asserts that the original design temperature of the three schools was 82 degrees Celsius and that if a low temperature heating plant is connected to a heating system designed to operate at 82 degrees Celsius, the heating capacities necessary to meet the building heat load will not be achieved and it would be necessary to retrofit the heating elements by adding more baseboards/radiant panels and/or increase the size of coils in an air handler in order to meet the peak heating load.[104]

MCW concludes, among other things, the following:

- FAES should have completed an energy model for each of the schools to analyze the operation of the atmospheric boilers, high efficiency boilers and heat pumps, as this is standard industry practice for the design of thermal heating plants using a combination of boilers and heat pumps;
- Achieving the natural gas consumption savings forecast in the CPCN Application was not possible in the three schools examined; and
- According to standard industry practice, FAES should have known of the issues identified in MCW's evidence and should have determined whether a full heating system retrofit may be needed to meet the natural gas reduction targets.[105]

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[100] Exhibit C1-6, Testimony of Donald Poole, p. 4.
[101] Ibid., pp. 5-6.
[102] Exhibit C1-8, DSD response to BCUC IR 4.1.
[103] Exhibit C1-6, MCW Report, p. 3.
[104] Ibid., pp. 3-4.
[105] Ibid., p. 7.

DSD goes on to state that, “the evidence it has adduced in this proceeding… militates in favour of a finding that FAES has breached sections 2.1(b), 2.1(c), and 2.3 of each ESSA with respect to schools equipped with Geothermal Heat Pump Systems.”[106]

In particular, DSD alleges the following specific breaches in design:

- Failure to perform the design in accordance with sound and currently accepted industry standards and codes of practice normally employed, at the time and place of performance, in projects of a similar type and nature;
- Failure to perform the design to ensure operational compatibility with the building system; and
- Failure to design the energy system to meet the thermal energy requirements of the building and operational compatibility of the building system.

According to DSD, the cumulative effect of these alleged design flaws means that at least a portion of the accumulated expenditures currently comprising the DDA and the proposed COS were not prudently incurred such that it would not be just or reasonable for FAES to now recover such amounts.[107]

In its final argument regarding prudency, DSD submits the following:

> …FAES and/or JCLP failed to undertake reasonable efforts to obtain an accurate understanding of the actual thermal energy demands of the Project Buildings prior to undertaking the Project. This is demonstrated by the significant difference between the forecasted annual thermal energy demands of the Project Buildings (10,605 MWh) and the actual annual thermal energy demand for the Project Buildings in the year preceding the COS Rate Application (6,504 MWh). Furthermore, FAES and/or JCLP failed to undertake the work necessary to conclude with any reasonable certainty that the Project could achieve the 93% natural gas savings (and resulting GHG emission reductions) that FEI originally promised the DSD that the Project could achieve and which were the ‘primary driver of the Project’.[108]

DSD argues that it is not, “alleging that the CPCN should not have been issued for the Project and is not asking the BCUC to ‘reassess’ the CPCN”. Instead, DSD “is alleging that a portion of the Capital Costs that are meant to be recovered via the Proposed COS Rate were not prudently incurred and is asking the BCUC to undertake a full prudency review of the these Capital Costs before it decides whether to switch the DSD to the Proposed COS Rate.”[109]

With regard to FAES’ statements that DSD’s distribution system is the “bottleneck”, DSD states: “In effect, FAES is arguing that [the] Energy Systems cannot achieve the efficiencies and the GHG emissions FEI promised they would achieve in the CPCN Application proceedings, unless the DSD Building Systems are upgraded and the DSD’s operation and maintenance of the DSD Building Systems is altered.” DSD argues that FAES and/or JCLP should have:

- Undertaken the work necessary to understand how the Energy Systems would interact with the DSD Building Systems and to understand how the DSD actually operates and maintains the DSD Building Systems; and

[106] Exhibit C1-8, DSD response to BCUC IR 2.2.1.
[107] Ibid., BCUC IR 2.3.
[108] DSD Final Argument, p. 52.
[109] Ibid., p. 55.

- Designed the Energy Systems so they would be operationally compatible with the DSD Building Systems (as required by the Service Agreements), and so they would achieve the efficiencies and the GHG emissions FEI promised they would achieve in the CPCN Application proceedings.[110]

DSD further argues that FAES' "allegation that the operation and maintenance of the DSD Building Systems has impacted the efficiency of the Energy Systems in any material way, based on isolated incidents, is purely speculative."[111]

3.4 FAES Rebuttal Evidence and Reply Argument

FAES responds to Poole's evidence by pointing out that Poole played a "limited part in the overall design of the Project and was not privy to the comprehensive process that was undertaken." FAES explains that the "compatibility of systems was resolved through JCCLP's design philosophy, equipment selection, and design of the sequence of operations." FAES provides the detailed sequence of operations for Nielsen Grove Elementary as Appendix L to its rebuttal evidence and states: "In simple terms, the system operates at low temperature (<60°C) until the point where higher heat transfer through the DSD's terminal equipment is required. At that point, high temperature (up to 90°C) is supplied to increase heat transfer and meet room set points."[112]

FAES further submits that JCCLP "did consider and install equipment such as higher temperature heat pumps on a case-by-case basis where the benefits exceeded costs." FAES cites JCCLP's heat pump selection for Neilson Grove as an example, stating that JCCLP selected a heat pump with an expanded output temperature range.[113]

With regard to MCW's evidence, FAES states that the materials that MCW indicates it reviewed for the purposes of preparing its report were not the complete record of the work done by FAES and JCCLP in the development of the TES.[114] FAES elaborates as follows:

> JCCLP, as part of its obligations, did precisely what MCW has suggested. Following completion of the initial feasibility study and the subsequent approval of the CPCN, JCCLP performed the detailed system design on a site by site basis including a detailed energy study for the Project that included an analysis of climate data, heating degree days, coefficient of performance of the equipment, floor space, operating hours, and building envelope characteristics.[115]

FAES submits that it and JCCLP did consider DSD's own heating distribution systems and the compatibility of the heat pump equipment, and through JCCLP's energy modelling analysis of the school sites, it determined that DSD's terminal systems (the thermal coils and radiant systems already existing in the schools) were capable of satisfying energy demand using lower temperatures during certain off-peak conditions.[116]

FAES further submits: "JCCLP's design philosophy was to incorporate high efficiency, lower temperature equipment during off-peak periods when lower operating temperatures could satisfy heating demands. However, during peak conditions (e.g., the only time period considered by MCW) the energy system was designed to rely on higher temperature equipment such as atmospheric boilers to satisfy higher levels of energy demand."[117]

FAES disputes MCW's use of peak capacity analysis, stating it yields "misleading results when assessing annual efficiencies." FAES submits that peak capacity conditions "occur infrequently over a very narrow window of the

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110 DSD Final Argument, pp. 55-56.
111 DSD Final Argument, p. 56.
112 Exhibit B-7, pp. 37-39; Appendix L.
113 Ibid., pp. 39-40.
114 Ibid., p. 29.
115 Ibid., p. 30.
116 Ibid.
117 Ibid.

coldest conditions that could reasonably be expected in any given year" and "rarely, if ever occur through a normal year."[118]

FAES also asserts that DSD staff have "employed measures which reduce system efficiency", citing as an example that DSD has used breaker panels to operate terminal equipment (fan coils) in unoccupied spaces like the Delview gymnasium. FAES states that while such an action avoids the immediate electricity cost associated with the heat pumps, the implication is that when turned back on, a large heating demand is placed on the system, forcing the use of the staged natural gas boilers to minimize room temperature recovery time.[119]

As part of its rebuttal evidence, FAES describes the results of the 2017 JCI Report related to how DSD's operation and maintenance of its terminal systems have impacted the system's efficiency, including the following:

- Blocked air returns in the buildings;
- Dirty heat exchanger fan coils; and
- Dirty air filters that had not been exchanged.[120]

In its reply argument, FAES references the same legal case as was referenced by DSD in its final argument – *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)*. FAES states that under the test in the aforementioned case, there is a "presumption of prudence that the DSD must rebut with some tangible evidence."[121]

FAES argues that DSD "has not met that burden when it comes to the capital cost" and submits: "When prudence reviews are undertaken, they are generally prompted by large overruns that might cause one to wonder if the project was well-managed. That is absent here." In particular, FAES points to the fact that the actual cost of the Project of $8,099,000 was within the AACE Class 3 parameters of minus 20 percent/plus 30 percent, and that the AACE Class 3 standards are what is required by the BCUC as part of its CPCN Guidelines.[122]

With regard to DSD's assertions about natural gas savings, FAES argues that it "never promised 93% natural gas savings" and elaborates as follows:

> The 93% natural gas savings figure referenced by the DSD appears to have been extracted from a table filed in the CPCN Proceeding that quoted from the JCLP contract with FAES. The data extracted by the DSD is for only three schools, and even then had been prepared before the detailed design had been completed. The DSD had been, or ought to have been, well aware that the 93% figure was not representative of the overall targeted natural gas savings across the entire Project.[123]

3.5 Panel Determination

In assessing the relevance of DSD's evidence in this proceeding, the Panel notes the following:

- The CPCN, along with the specifications for the project, was approved by the BCUC in 2012 following a public review process;
- Seven years have now passed since that decision and the BCUC has not received any request for a reconsideration or variance of the CPCN Decision from any party (including DSD who intervened in that proceeding) following the issuance of that decision, notwithstanding a direction from the BCUC to FAES

[118] Exhibit B-7, pp. 37-39; Appendix L, p. 33.
[119] Exhibit B-7, p. 33.
[120] Ibid., pp. 34-35.
[121] FAES Reply Argument, p. 39.
[122] Ibid.
[123] Ibid., p. 43.

in Order G-146-15A to provide submissions on "how it intends carrying out the rate setting mechanism going forward, whether a variance to the original CPCN decision (particularly on how the Delta SD deferral account balance is to be calculated), and an amendment to the Rate Agreement if necessary";[124] and

- DSD itself acknowledges in this proceeding that it is not seeking any determination beyond FAES' request to move to the COS Rate or alternatively, a determination of the appropriate COS Rate.

In the Panel's view, the evidence adduced by DSD is not relevant to the issue of determining the timing or propriety of the switch from the Market Rate to the COS Rate. The RDA reflects a COS offering which has been duly approved by the BCUC. The construction and capital costs of the assets associated with that service offering have similarly been approved by the BCUC in the CPCN Decision. The facilities have been providing thermal energy service to DSD since their completion. Prior to this proceeding, the BCUC has not received any complaints from DSD as to the adequacy or quality of the facilities or the service provided by FAES thereby.

Whether or not the facilities were constructed in accordance with the agreed specifications or are performing as the parties expected are questions that are more properly determined by a court adjudicating a breach of contract or construction claim, in respect of which the BCUC has no jurisdiction. In this regard, the Panel adopts the reasoning of the BC Court of Appeal in *Crestbrook Pulp and Paper Co. v. Columbia Natural Gas*, in which the court states:

> I am unable to distil from s. 87 any jurisdiction in the Commission to adjudicate between persons with a view to granting or refusing relief of the sort sought here. The essence of what Crestbrook seeks is a judgment for money paid under a mistake of fact, or for money paid for the use of Crestbrook, or for damages for breach of contract. The claims all sound in contract…[125]

If DSD believes that it has a sound basis to pursue a claim for damages against FAES for breach of contract at common law, it is free to do so by launching a court action. However, this is not a matter which the BCUC, as a creature of statute, has jurisdiction to adjudicate in the context of an application to determine revenue requirements and rates under the UCA, to which the just and reasonable standard applies.

The Panel also accepts FAES' final argument as an accurate statement of the BCUC's jurisdiction:

> Once the CPCN is granted and the project is constructed, the BCUC cannot just "reassess" whether a different project should have been built. The UCA includes provisions that protect the finality of CPCN decisions, and ensures that projects already constructed cannot retroactively have the project design "reassessed".[126]

The Panel further agrees with FAES that through the evidence adduced by Poole and MCW:

> The DSD seems to be alleging that the project approved by the BCUC was not capable of delivering the thermal service for which the DSD had contracted under the RDA, i.e., that the project as designed should not have been approved in the first place. It is not open to the DSD to make that argument over six years after the fact.[127]

For these reasons and particularly in light of the CPCN Decision, the Panel finds the evidence offered by Poole and MCW irrelevant to the task of determining the timing and propriety of the proposed switch from the Market Rate to the COS Rate as stipulated in the RDA. The Panel further declines to "reassess" the CPCN on the basis that the Panel lacks jurisdiction to do so.

[124] Appendix A to Order G-146-15A, p. 4.
[125] (1978) DLR (3d) 248 at 253-254.
[126] FAES Final Argument, p. 95.
[127] Ibid.

As for DSD's request for a prudency review, the Panel finds that DSD has not provided adequate evidence to rebut the presumption of prudence and therefore denies DSD's request for a prudency review of the project capital costs.

Based on the evidence, the actual capital costs of the project when compared to the forecast capital costs included in the compliance filing to Order G-71-12 are within the AACE Class 3 accuracy range of minus 20 percent/plus 30 percent. This degree of accuracy is prescribed in the BCUC's CPCN Guidelines[128] and supports the presumption of prudency.

With regard to DSD's submissions as to the change in scope and cost of the project and the lower GHG reductions, the Panel notes that all of these issues were explored during the CPCN proceeding and were clearly communicated in the BCUC's decision. The BCUC stated, among other things, the following:

> The Panel finds that the proposed approach provides Delta SD with some measure of protection from risk associated with capital cost overruns. However, there are significant limits to that protection…FEI has indicated that if project costs are in excess of $6.5 million, the Project can be down-scoped to a less expensive configuration. However, it appears to the Panel that this down-scoping will not reduce any of the fixed costs enumerated above….The Panel is also concerned that any down-scoping would result in less GHG emission reductions at the same or similar cost.[129]

The BCUC further commented as follows:

> Generally speaking, we are concerned with the risk that Delta SD is assuming…However, we also acknowledge that the contracts were negotiated in good faith by two sophisticated parties, and therefore, the Panel makes its determinations on that premise…
>
> …the Commission's usual practice of monitoring CPCN projects is by way of periodic construction progress reports in light of a potential need for prudency reviews. In this case, however, because of the two sophisticated parties involved, the Commission will not take on the monitoring role, including monitoring any re-scoping exercises. Delta SD will still have recourse by way of a complaint process pursuant to the provisions of the UCA.[130]

Subsequent to the BCUC's decision issued on March 9, 2012, which included the cautionary statements above, DSD proceeded with the project and signed the amended rates and rate design compliance filing dated April 3, 2012. The Panel notes that according to the evidence of both parties in this proceeding, the re-configuration and design of the TES which occurred subsequent to the CPCN proceeding was a collaborative effort between FAES and DSD. While concerns may have been raised by Poole, this was in his limited capacity as a sub-contractor involved in the project, and according to FAES' evidence, those concerns were considered and addressed where appropriate during the design of the TES.

The Panel also notes that DSD further participated in the regulatory proceedings when it intervened in the F2015/16 RRA, which occurred after the completion of the project and with the higher project capital costs having already been incurred. While DSD made submissions about the switch to the COS Rate in its final argument in the F2015/16 RRA proceeding, it did not raise the issue of prudency of the capital costs.

Furthermore, it was not until the current Application, when FAES filed for approval to switch to the COS Rate, that DSD raised the issue of prudency with the BCUC. If DSD believed that an issue of prudency existed related

[128] Order G-20-15, Appendix A, pp. 7-8.
[129] CPCN Decision, p. 72.
[130] CPCN Decision, p. 76.

to the amount of capital costs incurred, it would more appropriately have been raised when the actual capital cost amounts were finalized and the assets first placed into service, not seven years after the event.

The Panel acknowledges that, when compared to the forecasts provided by FAES in the Compliance Filing, there is a large discrepancy between forecast and actual natural gas and electricity usage. However, the Panel is satisfied that FAES has made reasonable efforts to increase the optimization of the central plant. The Panel agrees that it appears that a number of the ongoing issues are related to the distribution system, which is owned by DSD, and therefore it is incumbent upon DSD to implement the recommended improvements to the distribution system in order to further increase the system optimization. **The Panel therefore finds that FAES has taken appropriate and reasonable steps to improve the optimization of the TES.**

4.0 The Annual Cost of Service and the COS Rate

4.1 Description of the COS Rate and Annual Cost of Service

FAES seeks approval to switch to the COS Rate from the Market Rate, effective July 1, 2018. For the Fiscal 2018/19 year, the requested COS Rate is $0.253 per kWh, or $0.235 per kWh net of the DSD Rate Rider of $0.018 per kWh.[131]

The annual COS Rate and the Annual Cost of Service are defined in the RDA and have been previously described in Section 2.1 of this Decision.

The forecast Annual Cost of Service for F2018/19 is $1,528,000 and is broken down by FAES as follows:[132]

Table 4 – Breakdown of Fiscal 2018/19 Annual Cost of Service

Line	Particulars	2018/19
1	Cost of Service	
2	Cost of Natural Gas	244
3	Cost of Electricity	31
4	Energy Purchase Costs	275
5	Operation and Maintenance	250
6	Property Taxes	-
7	Depreciation Expense	191
8	Income Taxes	-
9	Return on Rate Base	398
10	Amortization of District Deferral Account	414
11		
12	**Annual Cost of Service**	**1,528**

As shown in the above table, the Annual Cost of Service for F2018/19 is comprised of five key components: Energy Purchase Costs, O&M expenses, depreciation expense, return on rate base, and the amortization of the DDA.

4.2 Forecast versus Actual Annual Cost of Service

In evaluating the Annual Cost of Service, the BCUC and DSD pursued in IRs the comparison between the Annual Cost of Service forecasts provided by FAES in the Compliance Filing and the actual results.

[131] Exhibit B-1-1, Evidentiary Update, p. 2.
[132] Exhibit B-1-1, Appendix A, p. 1.

The forecasts for F2012/13 through F2017/18 provided in the Compliance Filing are as follows:[133]

Table 5 – Forecast Cost of Service for F2012/13 through F2017/18

Line	Particulars	Reference	2012	2013	2014	2015	2016	2017
1	Revenue Requirement							
2	Cost of Natural Gas	Schedule 2, Line 17	48	114	127	134	142	147
3	Cost of Electricity	Schedule 3, Line 17	26	174	228	234	241	248
6	Operation and Maintenance	Schedule 4, Line 19	144	214	218	223	264	269
7	Property Taxes	Schedule 4, Line 30	-	-	1	4	8	10
8	Depreciation Expense	Schedule 10, -(Line 17 + Line 38)	64	142	156	160	163	163
9	Income Taxes	Schedule 5, Line 17	(276)	(464)	(262)	(100)	(9)	49
10	Earned Return	Schedule 7, Line 24	157	344	373	371	368	356
11								
12	Annual Revenue Requirement	Sum of Lines 1 through 10	163	524	841	1,026	1,176	1,243

The actual/projected results for F2012/13 through F2017/18 are as follows:[134]

Table 6 – Actual/Projected Cost of Service for F2012/13 through F2017/18

Line	Particulars	Reference	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
1	Cost of Service							
2	Cost of Natural Gas	Schedule 3, Line 13	23	249	228	247	235	252
3	Cost of Electricity	Schedule 4, Line 9	0	34	31	26	33	32
4	Energy Purchase Costs		23	282	260	273	268	284
5	Operation and Maintenance	Schedule 5, Line 11	3	129	153	224	263	210
6	Property Taxes	Schedule 5, Line 22	-	-	-	-	-	-
7	Depreciation Expense	Schedule 11, -(Line 26 + Line 55)	7	118	179	185	185	187
8	Income Taxes	Schedule 6, Line 18	-	-	-	-	-	-
9	Return on Rate Base	Schedule 8, Line 24	31	333	437	415	437	390
10	Amortization of District Deferral Account	Schedule 12, Line 9	-	1	20	73	131	302
11								
12	Annual Cost of Service	Sum of Lines 2 through 9	65	864	1,049	1,170	1,283	1,373

With the exception of the initial year of the RDA term, the actual/projected Annual Cost of Service has been higher than the forecast Annual Cost of Service. However, excluding the impacts of the lack of income tax deductions and the amortization of the DDA, the actual Annual Cost of Service results are lower than the annual amounts forecast in the Compliance Filing.

The components of the Annual Cost of Service are discussed below.

Income Taxes

In the F2015/16 RRA proceeding, FAES explained why the income taxes were incorrectly forecast to be a credit over the first four years of the RDA term:

> It is important to note that the CPCN Application was submitted by FortisBC Energy Inc. (FEI), meaning that the Capital Cost Allowance benefits would have been monetized in the years that they occurred, rather than the losses carried forward as they are now…As FAES does not generate enough taxable income to recognize these amounts in current taxes, FAES reduces the taxes to zero and carries the balance forward for offsetting future taxes.[135]

Amortization of the DDA Balance

The largest component of the F2018/19 Annual Cost of Service is the amortization expense related to the DDA, which FAES calculates to be $414,000. FAES forecasts the DDA balance as of June 30, 2018 to be $3,925,000.[136]

[133] Exhibit B-4, BCUC IR 7.1.
[134] Exhibit B-1-1, Appendix A, Schedule 2.
[135] F2015/16 RRA, Exhibit B-4, BCUC IR 2.1.
[136] Exhibit B-1-1, Appendix A, p. 3.

The DDA is defined in the RDA as: "the record of the cumulative difference between the Annual Cost of Service and revenues, including a provision for interest at the AFUDC rate."[137]

The revenues received by FAES are based on the Market Rate charged to DSD. The initial Market Rate was set by taking the DSD's business as usual (BAU) cost of $941,000 and dividing this cost by the estimated thermal energy demand of 10,600 MWh.[138]

FAES states that the Market Rate has remained significantly below expectations since the inception of service.[139] As a result, there have been large annual variances between the Market Rate and the COS Rate which have been accumulating in the DDA. FAES states that there are two factors which have contributed to the significant disparity between the expected Market Rate and the actual revenue received:

1. Natural gas prices fell significantly since the Market Rate was calculated, reducing the Market Rate significantly. DSD and FAES both expected natural gas prices to increase at the time the RDA and ESSAs were negotiated.
2. The anticipated thermal energy demand, which was the denominator used to calculate the initial Market Rate, did not materialize. This created a low initial market rate which was then used as the basis for all future years' Market Rates.[140]

Energy Purchase Costs

FAES forecasts natural gas costs of $244,000 and electricity costs of $31,000 for F2018/19. It states that it forecasts the costs for electricity and natural gas using the prevailing rates and a forecast of the fuel consumption based on the sites in service and their design performance characteristics. The Energy Purchase Cost variances have been previously described in Section 3.0 of this Decision.

O&M Expenses

The O&M expenses are comprised of the following costs: labour, fees and administration, contractor costs, and overheads and shared services allocation. For F2018/19, FAES forecasts O&M expenses of $250,000.[141]

The following tables compare the forecast O&M expenses provided in the Compliance Filing and the actual/projected O&M expenses for F2012/13 through F2018/19.

Table 7 – Forecast O&M per Order G-71-12 Compliance Filing[142]

($000's), unless otherwise stated
Schedule 5

Line	Particulars	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
1	Gross O&M				Forecast			
2	Contractor Costs	134	199	203	207	211	216	364
3	Overheads and Shared Services Allocation	34	50	51	52	53	54	91
4	Total Gross O&M Expenses	168	249	254	259	264	269	290
5	(Less): Capitalized Overhead	(24)	(35)	(36)	(36)	-	-	(64)
6	Net O&M	144	214	218	223	264	269	250

[137] Exhibit B-1, Appendix E, RDA Section 1.1(q).
[138] Exhibit B-1, p. 8.
[139] Exhibit B-1-1, p. 14.
[140] Exhibit B-1, p. 15.
[141] Exhibit B-1-1, Appendix A, pp. 1-2.
[142] Exhibit B-4, BCUC IR 10.1, Table 2.

Table 8 – Actual/Projected O&M[143]

Schedule 5

Line	Particulars	Reference	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
1	Gross O&M								
2	Labour Costs		-	-	30	28	26	31	41
3	Fees & Administrations Costs		3	26	18	34	1	18	59
4	Contractor Costs		-	90	80	111	184	141	137
5	Overheads and Shared Services Allocation 1		-	35	50	51	52	53	54
6									
7	Total Gross O&M Expenses	Line 2 + Line 7	3	151	178	224	263	244	290
8									
9	(Less): Capitalized Overhead	-Line 7 x 14%	-	(21)	(25)	-	-	(34)	(41)
10									
11	Net O&M	Line 7 + Line 9	3	129	153	224	263	210	250
12									
13	1- TESDA recovery								

Labour Costs

FAES did not forecast any labour costs as part of the Compliance Filing due to its original expectations that DSD would provide these services.[144] During the first two years of the RDA, the employees who provided services to DSD were employed by FEI and were not FAES employees; therefore, the labour charges were included in fees and administrative costs rather than annual labour costs.[145] Commencing in F2014/15, FAES utilized its own direct employees and charged the labour related to DSD via timesheet entries.[146]

Fees & Administration Costs

FAES describes the fees & administration costs as generally including the following:

- Approximately $9,000 annual fee to the BC Safety Authority for certification of the boilers;
- Annual charges from the BCUC; and
- Legal fees for rate applications.[147]

Contractor Costs

The F2018/19 forecast contractor costs of $137,000 relate to FAES' contract with JCI to provide preventative maintenance on the equipment.

FAES explains that the contractor costs between F2013/14 and F2016/17 included amounts related to "simple maintenance and emergency response tasks" performed by DSD facilities staff in addition to work done by third party contractors.[148] FAES was asked in BCUC IR 15.4 to explain why, as of 2017, it is no longer utilizing DSD facilities staff for O&M work on the equipment. FAES responded as follows:

> FAES had originally hired DSD to provide staff to perform ongoing maintenance and emergency response, as it was thought to be a potential source of cost savings to use staff already on site…
>
> Through this [JCI's] review, a key finding was that many of the energy system parameters at the three sites had been reconfigured by DSD staff without proper coordination or communication with FAES. The contracting arrangement with DSD had also led to some duplication of services.

[143] Exhibit B-1-1, Appendix A, Schedule 5.
[144] Exhibit B-4, BCUC IR 10.1.
[145] Ibid., BCUC IR 12.2.
[146] Ibid., BCUC IR 12.1.
[147] Ibid., BCUC IR 14.1.
[148] Exhibit B-4, BCUC IR 15.2, 15.3.

> For example, trouble calls were often reported and initially attended by DSD maintenance staff. DSD staff would attempt simple corrections, but would contact JCI for most trouble calls to diagnose and repair the system…
>
> Accordingly, in an effort to stabilize operations, simplify trouble call handling, reduce overlap, and decrease costs, FAES provided notice to the DSD of its intention not to rehire the DSD's maintenance staff for the 2017/18 year. Following this decision, operations have improved and stabilized, and FAES has received fewer complaints from the DSD regarding performance. FAES has also seen a reduction in overall maintenance costs.[149]

In response to DSD IR 4.1, FAES stated that the contract awarded to JCI was not awarded through a competitive bidding process and was instead a result of negotiations between FAES and JCI. FAES' rationale for this is that JCI has "unique knowledge and expertise" due to its involvement in the design, construction, commissioning and optimization of the mechanical systems. Also, FAES submits that it was able to gain comfort that the results of its negotiated rates with JCI were comparable to rates obtained in other FAES projects which were subject to competitive bidding processes.[150]

Overheads and Shared Services Allocation

The overhead and shared services allocation amount for F2018/19 of $54,000 is related to FAES' Thermal Energy Services Deferral Account (TESDA). As part of Order G-71-12, FAES was directed to include $50,000 as a forecast for overhead charges to be allocated to DSD. FAES included the amount of $50,000 in the F2014/15 Annual Cost of Service and has since been escalating this amount by inflation annually.[151]

FAES explained that while it is currently allocated annual overhead services charges from FEI in amounts of approximately $250,000, it has not yet allocated any indirect costs to DSD beyond the allocation of $50,000 plus inflation each year from the TESDA, which relates to past support services provided prior to ceasing additions to the TESDA account in 2014. FAES submitted that it is not seeking to add additional indirect costs retroactively related to the shared services charges from FEI to FAES; however, indirect costs for future years could be a line item in the future Annual Cost of Service.[152]

FAES was asked in BCUC IR 17.8 to provide a discussion of alternative allocation methods which could be utilized to allocate costs from the TESDA to DSD. FAES responded that it explored the following four alternative methods:

- Use a percentage of direct O&M as was originally done to arrive at the amount of $50,000;
- Allocate each line item in the TESDA as well as the FAES overheads;
- Allocate on the basis of the plant in service; or
- Allocate using the predicted amounts each year at the outset of the contract approvals.[153]

At the present time, FAES supports the use of the existing allocation method and amount because it, "has the benefit of being consistent with the expectations of the parties, is very administratively simple, creates a level allocation in real dollars across the initial [RDA] term, does not adversely affect the other customers of FAES, is consistent with the approach for other existing customers of FAES, and produces the lowest and most consistent allocation of the four methods discussed here."[154]

[149] Exhibit B-4, BCUC IR 15.4.
[150] Exhibit B-3, DSD IR 4.1.
[151] Exhibit B-1-1, Appendix A, p. 2.
[152] Exhibit B-4, BCUC IR 17.4, 17.4.1.
[153] Exhibit B-4, BCUC IR 17.8.
[154] Ibid.

Depreciation and Return on Rate Base

FAES states that it uses approved depreciation rates for the assets. With regard to financing costs and ROE, FAES uses a deemed capital structure of 40 percent equity and 60 percent debt as per Order G-31-12, and a negotiated ROE premium of 50 basis points on the benchmark utility ROE of 8.75 percent. FAES further states that it has updated the cost of debt for the F2018/19 COS Rate using the BCUC-approved method, which results in a cost of debt rate of 4.49 percent and is consistent with BBB-rated distribution utilities.[155]

4.3 DSD Evidence and Arguments

DSD submitted evidence from Will Cleveland of ReShape Strategies (Cleveland, ReShape). Cleveland was requested to respond to questions posed by DSD related to the forecast versus actual cost of service, thermal energy load and cost of energy.[156]

In response to BCUC IR 3.1.1 on DSD's evidence, DSD stated that Cleveland's evidence, "confirms that FAES made errors in its thermal energy load forecast." DSD further stated that Cleveland's evidence, "rebuts FAES' current claim that the 'cost of service aligns with forecasts'" and that Cleveland's evidence confirms the following:

- The actual cost of service for the thermal energy project is much higher than the original cost of service projection; and
- The actual cost of energy from heat-pump based sources included in the thermal energy project is much higher than the original projected cost of energy.[157]

Cleveland utilizes "unit cost of service" calculations to compare the original cost of service forecasts in the CPCN Application to the actual cost of service results. He states that as of F2016/17, the unit cost of service (excluding the amortization of the DDA) was 44 percent higher than the original forecast unit cost of service adjusted for fuel rate variances. Cleveland states that the primary driver of the higher-than-forecast unit cost of service is errors in load forecasting.[158]

Cleveland asserts that the load forecast variances are attributable to two different errors and describes these errors as follows:

- **Load Forecast Error 1** – FAES over-estimated how much of the DSD sites' thermal energy would be supplied by the FAES equipment. This error represents actual load that the DSD sites have had and continue to have, and which FAES represented could and would be met by FAES equipment but cannot be due to the pre-existing secondary side configuration of the DSD sites, and is instead met by DSD equipment.
- **Load Forecast Error 2** – FAES over-estimated the total thermal energy demand of the DSD sites (i.e. it did not develop an accurate estimate of the weather-adjusted thermal energy load of the sites). Thermal energy load was estimated using gas consumption from prior years, so FAES likely over-estimated the efficiency of the existing equipment.[159]

Regarding recovery of the DDA, Cleveland submits the following:

> FAES' position appears to be that DSD should bear 100% of the risk and cost impacts of the load forecast error as well as the related impact of the MR being lower than forecast. If DSD is required to pay the entire deferral account balance including FAES' earned return, not only

[155] Exhibit B-1-1, Appendix A, pp. 2-4.
[156] Exhibit C1-6, Testimony of Will Cleveland.
[157] Exhibit C1-8, DSD response to BCUC IR 3.1.1.
[158] Exhibit C1-6, Testimony of Will Cleveland, pp. 5-8.
[159] Exhibit C1-6, Testimony of Will Cleveland, p. 10.

> would FAES not bear any costs for its errors, but FAES would actually be <u>rewarded</u> for its load forecast errors by getting to earn its full return on the deferral account balance.[160]

When asked by the BCUC about the relevance of Cleveland's testimony given that the load forecast was reviewed by the BCUC as part of the CPCN Application proceeding and subsequently reviewed and approved as part of the BCUC's approval of the rate design and rate in Order G-88-12, DSD responded:

> …any prior Commission approval of FAES' load forecast projections must be reassessed in light of the evidence of Mr. Poole and MCW Consultants Ltd. concerning what FEI/FAES knew or ought to have known about the performance of the Geothermal Heat Pump Systems at the time that the system was designed.[161]

However, DSD went on to clarify in its response that it, "is not seeking a determination from the Commission beyond a denial of FAES' request to move to the COS Rate, or, in the alternative, a determination of the appropriate COS Rate."[162]

In its final argument, DSD states that it:

> …does not dispute that, based on the facts known at the present time, and the limited information provided by FAES in this proceeding:
>
> a. the operating costs of the Project are being managed appropriately by FAES;
>
> b. the overhead costs of the Project do not include some indirect costs; and
>
> c. FAES has incurred costs to provide service and has had to finance those costs with both debt and equity in anticipation of future recovery.[163]

However, DSD argues that the "fact that the Current Total Cost of Service in absolute dollars is not significantly different from the Forecasted Total Cost of Service, should have no bearing on the BCUC's decision as to whether the DSD should be switched to the Proposed COS Rate." DSD argues that this "often-repeated metric by FAES is completely misleading with respect to the performance of the Project." DSD describes the BCUC's mandate as follows:

> Under the UCA, the BCUC is charged with regulating rates. In this proceeding, the BCUC is tasked with determining, *inter alia*, whether the <u>Proposed COS Rate</u>, which is significantly higher than the <u>2012 forecast COS Rate</u>, is just and reasonable within the meaning of the UCA. The BCUC is not charged with determining whether the Current Total Cost of Service is just and reasonable in light of the Forecasted Total Cost of Service.[164]

DSD submits the following regarding the thermal energy load and the Annual Cost of Service:

> The reduction in thermal energy load means that Total Cost of Service should be far lower than the Forecasted Total Cost of Service because, all else being equal, a reduction in energy demand will result in a reduction in fuel consumption and therefore fuel costs. The sharp decline in natural gas prices and the Project's near-total reliance on gas boilers (as opposed to heat pumps) should also decrease the Total Cost of Service. Nevertheless, the Total Cost of Service remains relatively close to the Forecasted Total Cost of Service. FAES somehow suggests that this is an indication that the Project is performing well, as the parties expected it to. The DSD disagrees.[165]

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[160] Exhibit C1-6, Testimony of Will Cleveland, p. 15.
[161] Exhibit C1-8, DSD response to BCUC IR 3.2.
[162] Ibid., BCUC IR 3.3.
[163] DSD Final Argument, p. 48.
[164] DSD Final Argument, p. 41.
[165] Ibid., p. 42.

4.4 FAES Rebuttal Evidence and Reply Argument

FAES states in its rebuttal evidence that the Annual Cost of Service is lower than projected and Cleveland's evidence is "materially flawed." FAES identifies the following two "significant issues" with Cleveland's methodology:

- Cleveland conducted his analysis based on unit costs of energy, rather than total cost of service. Given that there is only one customer paying the entire cost of service, the meaningful number is the total cost of service in dollars, which is lower than originally projected. The only practical relevance of unit costs is to facilitate dividing up the total annual cost for monthly billing.
- Cleveland compares actual unit costs to forecast unit costs based on a different project configuration from what had eventually been built, and he did not make any adjustments necessary to address the project's reconfiguration.[166]

With regard to Cleveland's unit cost analysis, FAES states that his, "observation holds true when the revenue requirements must be allocated among multiple customers, since lower (greater) demand means that the total revenue requirements have to be divided among fewer (more) units of energy." However, when there is only one customer, as is the case with DSD, that customer is required to pay the entire cost of service regardless of the system demand. FAES further states the following:

> The reality is that the lower thermal energy demand relative to the forecast has no impact on the responsibility for payment of the total cost of service by the DSD. The absence of other customers eliminates the effects of different levels of thermal energy sales on the costs that the DSD is responsible to pay. Thus, the contracts are set up for the DSD to pay the cost of service over the life of the contract regardless of the thermal energy demand. As shown already, that cost of service is below the original projections.[167]

In response to DSD's argument regarding the BCUC's considerations under the UCA, FAES states that the definition of what constitutes a "rate" under the UCA is "much broader than simply a unit price", citing as examples that the BCUC "routinely relies on the rate setting sections (sections 59 to 61) as the authority for approval of deferral accounts/account amortization periods and depreciation rates for capital because they influence the amount recovered from customers."[168]

FAES further argues that, "in seeking to draw a bright line distinction between total cost of service and rates, the DSD is overlooking the fact that the RDA is a cost of service rate regime. Not only is total cost of service 'relevant' to cost of service ratemaking, it is the <u>central focus</u> of all cost of service rate setting…" FAES explains that under a cost of service rate regime, the rates approved by the BCUC for the upcoming year flow from the BCUC's determination of the total forecast costs required to provide an appropriate level of service to customers; hence the reason that annual general rate applications such as the current Application are called "revenue requirements applications."[169]

FAES submits that while DSD has "fixated on unit prices" and the impact of load on those unit prices, dividing the total revenue requirements into unit costs had no effect on the Annual Cost of Service. FAES states that the "only practical impact that the load forecast variance has had (apart from reducing the MR and fuel costs to the benefit of the DSD for the past five years) was to change the timing of when the total revenue requirements is collected from the DSD within the year."[170]

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[166] Exhibit B-7, p. 19.
[167] Ibid., p. 22.
[168] FAES Reply Argument, p. 20.
[169] Ibid., pp. 20-21.
[170] Ibid., p. 21.

4.5 Panel Determination

The Panel has previously found in Section 2.2 of this Decision that in light of the regulatory compact and the lack of specified constraints on the timing of any application for BCUC approval of a switch from the Market Rate to the COS Rate, it is just and reasonable to approve the Application by giving effect to FAES' right to trigger the switch at this time. **The Panel further finds it is just and reasonable for FAES to recover its prudently incurred costs of providing service to DSD, including an allowed return on investment. These costs are clearly defined in section 1.1(d) of the RDA (the "Annual Cost Service") and, contrary to DSD's argument,[171] the Panel finds that there is sufficient evidence on the record, as detailed in Section 4.2 of this Decision, to show that the Annual Cost of Service amounts are reasonable and in accordance with the RDA.** While DSD has questioned the prudency of certain capital costs, the Panel has found that there is a lack of evidence to rebut the presumption of prudence.

Of the five categories of annual costs incurred - Energy Purchase Costs, O&M, depreciation expense, return on rate base and amortization of the DDA - three of these are calculated in accordance with BCUC-approved methodologies and rates or prevailing commodity rates (i.e. depreciation expense, return on rate base and Energy Purchase Costs). The annual DDA amortization expense is calculated in accordance with the method prescribed in the RDA. With regard to the remaining category, O&M expense, the Panel considers that FAES has demonstrated through the evidence in this proceeding that it is making best efforts to control the level of O&M expenses through practices such as identifying and eliminating situations where duplication of work is occurring.

The Panel agrees with FAES that DSD's evidence and analysis regarding the "unit cost of service" is flawed, as DSD is the sole customer responsible for the full cost of service amount; thus, regardless of the amount of thermal energy consumed, the Annual Cost of Service would be the same (with the exception of the impact of consumption on the variable Energy Purchase Costs).

The key outcome of the forecast thermal energy demand being higher than the actual demand is the impact that this forecast had on setting the initial Market Rate. This low initial Market Rate has in turn impacted the annual revenues received by FAES and has contributed to the build-up of the DDA balance due to the significant difference between the Market Rate and the COS Rate. However, the Panel agrees with FAES that the significance of the forecast versus actual thermal energy demand is minimal beyond the aforementioned impact on the initial Market Rate and has no bearing on the reasonableness of the Annual Cost of Service or the COS Rate.

The Panel notes FAES' statement in response to BCUC IRs that it is not seeking to add additional indirect costs retroactively related to the shared services charges from FEI to FAES but that indirect costs for future years could be a line item in the future Annual Cost of Service. The Panel further notes FAES' statement that it supports the use of the existing method for allocation of the TESDA costs at the present time.[172] **Should FAES decide in the future to add an amount in the Annual Cost of Service for indirect costs related to shared services charges from FEI to FAES or to change the TESDA allocation method, FAES is directed to file for approval of these changes with the BCUC prior to including the amounts in the Annual Cost of Service and COS Rate charged to DSD.**

5.0 Phase-in and Implementation of the COS Rate

There are two issues regarding the implementation of the COS Rate: (i) whether the COS Rate should be phased in; and (ii) what the effective date of the permanent COS Rate should be.

[171] DSD Final Argument, p. 48.
[172] Exhibit B-4, BCUC IR 17.4, 17.4.1, 17.8.

As stated previously, the amortization of the DDA is defined in the RDA as the annual amount necessary to amortize the DDA balance, either credit or debit, over the remaining years in the term or 10 years, whichever is longer.[173] The initial RDA term is 20 years and FAES and DSD are currently in the seventh year of the RDA term. Accordingly, depending on the length of the delay in switching to the COS Rate or the length of a potential phase-in, a portion of the DDA balance may remain unrecovered.

In response to BCUC IR 3.1, FAES described the following scenario in which it would not be able to recover the balance in the DDA:

- The DSD and/or FAES provides six months' notice prior to the end of the initial term that they will not renew the contract, thereby terminating the agreements; and
- The DSD exercised its right to require FAES to remove the Energy Systems at FAES' cost rather than DSD's right to purchase the Energy Systems.[174]

FAES further stated:

> In light of the size of the DDA balance and the rate at which it is expected to grow, FAES would have little prospect of recovering the unamortized balance through sale or renewal if the Commission were to prevent the changeover [to the COS Rate] from occurring until after year 10 of the term and depreciation rates remain unchanged. It is this scenario that gives rise to FAES' concern about not being afforded an opportunity to earn a fair return on, and the return of, its investment.[175]

In consideration of the above, FAES argues that at most, a phase-in of the COS Rate should extend three years.[176]

In its supplementary final argument regarding a potential phase-in of the COS Rate, DSD states the following:

> If, however, notwithstanding the DSD's position, the BCUC decides to issue an Order granting the Application and requiring the DSD to pay the Proposed COS Rate…the DSD submits that the switch to the Proposed COS Rate should occur effective July 1, 2019 and should not be delayed or phased-in over a longer period of time.[177]

DSD provides further clarity regarding the effective date of the COS Rate and the phase-in period in its submission dated March 12, 2019. In this submission, DSD acknowledges that Order G-77-18 approved interim rates for F2018/19 effective July 1, 2018. However, DSD confirms that it is requesting that if the BCUC directs a switch to the COS Rate, the permanent COS Rate be made effective July 1, 2019 instead of July 1, 2018, which would effectively result in a one-year phase-in of the COS Rate.[178]

DSD explains that the basis for its request for a one-year phase-in is that it "faces unique budgeting constraints that will restrict its ability to pay a COS Rate retroactively to July 1, 2018." DSD further states the following:

> If the DSD is required to pay a COS Rate commencing on July 1, 2019, it will likely be necessary for the DSD to implement service reductions to accommodate a significant change to its 2019/2020 budget. As the exact amount of any COS Rate resulting from a one-year phase-in remains unknown to the DSD, the extent of any such service reductions likewise remains unknown at this point. However, commencing a switch to the COS Rate on July 1, 2019 will

[173] Exhibit B-1, Appendix E, RDA Section 1.1(d).
[174] Exhibit B-4, BCUC IR 3.1.
[175] Ibid.
[176] FAES Final Argument, p. 111.
[177] DSD Supplementary Final Argument dated March 5, 2019, p. 2.
[178] DSD Clarification of Supplementary Final Argument dated March 12, 2019, p. 2.

better afford the DSD an opportunity to determine the possible effects of such a switch during the 2019/2020 fiscal year.[179]

FAES states that it, "continues to hold the view that a phase-in is unwarranted, and that the COS Rate should be effective July 1, 2018 as sought in the Application" and that "the delay contemplated by the DSD's proposal, although only a one-year delay, would increase intergenerational inequity and amplify the future challenges for the DSD."[180]

FAES explains the impact of the one-year delay in implementing the COS Rate as follows:

> The DSD's proposal would yield a higher 2019/2020 unit rate than $0.253/kWh and a higher total thermal energy cost (other things being equal) because of the combination of (a) the additional unrecovered amount from 2018/2019 that would have to be deferred to the District Deferral Account ("DDA"), (b) one more year of AFUDC on the growing DDA balance, and (c) the amortization of the DDA over a period that is one year shorter. The forecast COS Rate for the 2019/2020 rate year will be re-calculated in the 2019 Revenue Requirements Application, to be filed in the next few months.[181]

FAES also expresses concerns that the BCUC's approval of a phase-in of the COS Rate may be, "misinterpreted by the DSD as an invitation to re-argue its allegations relating to the recoverability of the DDA balance in the next revenue requirements application."[182]

Panel Determination

The Panel has previously found in this Decision that it is just and reasonable for FAES to recover its costs of providing service to DSD, including an allowed return on investment. If the switch to the COS Rate was delayed beyond three years or did not occur at all during the initial RDA term, FAES would not be provided the opportunity to earn its allowed return on invested capital and would potentially not even be provided the opportunity to recover its prudently incurred costs of providing service to DSD. **The Panel finds the aforementioned scenario to be unjust and unreasonable under section 59(5) of the UCA.**

The Panel acknowledges that the interim Market Rate was made effective July 1, 2018 and that FAES has applied for the COS Rate to be made permanent effective July 1, 2018. **However, the Panel finds it reasonable to delay the switch to the COS Rate to July 1, 2019 to provide some accommodation for DSD's unique budgeting constraints. The Panel therefore declines FAES' application to make the COS Rate permanent effective July 1, 2018.** The Panel notes that DSD has acknowledged that the one-year phase-in of the COS Rate will further increase the COS Rate over the remainder of the initial RDA term. This increase is due to the addition to the DDA balance resulting from the variance between the COS Rate and the actual revenues collected for Fiscal 2018/19.

Based on the above, the Panel orders the following:

1. **The switch from the Market Rate to the COS Rate is approved, effective July 1, 2019.**
2. **The Market Rate, which was approved on an interim basis by Order G-77-18, is made permanent effective July 1, 2018.**
3. **The difference between the actual Annual Cost of Service and the revenues collected for Fiscal 2018/19, plus an amount for AFUDC, is to be recorded in the DDA for recovery over the remaining years of the RDA term, beginning July 1, 2019.**

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[179] DSD Clarification of Supplementary Final Argument dated March 12, 2019, p. 3.
[180] FAES Supplementary Reply Argument dated March 5, 2019, p. 1.
[181] Ibid., p. 2.
[182] Ibid.

To be clear, while the Panel has approved the one-year delay in implementation of the COS Rate to July 1, 2019, **the Panel finds the Annual Cost of Service and the COS Rate, which include the recovery of the DDA balance over the remainder of the RDA term, to be just and reasonable.**

In consideration of the above orders, the Panel directs FAES to file the following on or before May 31, 2019:

1. **Tariff pages reflecting the permanent Market Rate effective July 1, 2018; and**
2. **An application for approval of the Fiscal 2019/20 Annual Cost of Service and COS Rate, which includes the information contained in Appendix A to the Application, updated for Fiscal 2019/20. FAES must include a breakdown and description of the forecast 2019/20 Annual Cost of Service and the financial schedules showing the actual 2012/13 through 2017/18 results, projected 2018/19 results and the forecast for 2019/20.**

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of April 2019.

Original signed by:

W. M. Everett, QC
Panel Chair/Commissioner

Original signed by:

A. K. Fung, QC
Commissioner

Original signed by:

M. Kresivo, QC
Commissioner

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ORDER NUMBER
G-84-19

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Alternative Energy Services Inc.
Application for Approval of the Fiscal 2018/2019 Revenue Requirements and Cost of Service Rates for the Thermal Energy Service to Delta School District No. 37

BEFORE:
W. M. Everett, QC, Panel Chair/Commissioner
A. K. Fung, QC, Commissioner
M. Kresivo, QC, Commissioner

on April 16, 2019

ORDER

WHEREAS:

A. On February 8, 2018, pursuant to sections 59-61 of the *Utilities Commission Act* (UCA), FortisBC Alternative Energy Services Inc. (FAES) applied to the British Columbia Utilities Commission (BCUC) for approval of its revenue requirements and rates for the thermal energy service to Delta School District No. 37 (DSD). FAES applies to switch from the current market rate to the cost of service (COS) rate (COS Rate) of $0.223 per kilowatt-hour (kWh), effective July 1, 2018, for the fiscal and contract year from July 1, 2018 to June 30, 2019 (Application);

B. On April 5, 2018, pursuant to Order G-56-18, a procedural conference was held to address issues related to the appropriate level of intervention in the proceeding, the appropriate regulatory process, and whether the BCUC should approve interim rates at FAES' proposed COS Rate effective July 1, 2018. FAES and DSD attended and made submissions at the procedural conference;

C. By Orders G-77-18, G-83-18, G-118-18, G-228-18 and G-31-19, the BCUC established a regulatory timetable which included the following: intervener registration; BCUC and intervener information requests (IRs) on the Application; the filing of DSD evidence; BCUC and FAES IRs on DSD's evidence; the filing of rebuttal evidence by FAES; BCUC and DSD IRs on FAES' rebuttal evidence; and written final and reply arguments. The BCUC also approved the existing market rate mechanism and resulting market rate on an interim and refundable basis, effective July 1, 2018;

D. On February 15, 2019, by Order G-36-19, the BCUC further amended the regulatory timetable to provide DSD and FAES the opportunity to submit supplementary final and reply arguments on a potential phase-in of the COS Rate;

E. Based on FAES and DSD's supplementary arguments, the BCUC issued a letter dated March 6, 2019 seeking clarification from DSD. FAES was provided an opportunity to reply to DSD's clarifying submission; and

F. The BCUC has reviewed the evidence and arguments in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59-61 of the UCA, for the reasons provided in the decision issued concurrently with this order, the BCUC orders as follows:

1. The Market Rate, which was approved on an interim basis by Order G-77-18, is made permanent, effective July 1, 2018.

2. The switch from the Market Rate to the COS Rate is approved, effective July 1, 2019.

3. The difference between the actual Annual Cost of Service and the revenues collected for the Fiscal 2018/19 fiscal and contract year, plus an amount for Allowance for Funds Used During Construction (AFUDC), is to be recorded in the District Deferral Account (DDA) for recovery over the remaining years of the Rate Development Agreement (RDA) term, beginning July 1, 2019.

4. FAES is directed to file the following on or before May 31, 2019:
   a. Tariff pages reflecting the permanent Market Rate effective July 1, 2018 in compliance with the terms of this order; and
   b. An application for approval of the Fiscal 2019/20 Annual Cost of Service and COS Rate, which includes the information contained in Appendix A to the Application, updated for Fiscal 2019/20. FAES must include a breakdown and description of the forecast 2019/20 Annual Cost of Service and the financial schedules showing the actual 2012/13 through 2017/18 results, projected 2018/19 results and the forecast for 2019/20.

5. FAES is directed to comply with all of the directives stated in the decision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of April 2019.

BY ORDER

Original signed by:

W. M. Everett, QC
Commissioner

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Alternative Energy Services Inc.
2018/2019 Revenue Requirements and Cost of Service Rates Application
for the Thermal Energy Service to Delta School District No. 37

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated February 28, 2018 - Appointing the Panel for the review of the FortisBC Alternative Energy Services Inc. 2018/2019 Revenue Requirements and Cost of Service Rates Application for the Thermal Energy Service to Delta School District No. 37
A-2	Letter dated March 8, 2018 – BCUC Order G-56-18 issuing Regulatory Timetable for Procedural Conference
A-3	Letter dated April 12, 2018 – BCUC Order G-77-18 issuing a Regulatory Timetable with Reasons for Decision
A-4	Letter dated April 27, 2018 – BCUC Order G-83-18 issuing an amended Regulatory Timetable
A-5	Letter dated May 22, 2018 – BCUC Information Request No. 1
A-6	Letter dated June 29, 2018 - BCUC Order G-118-18 issuing an amended Regulatory Timetable
A-7	Letter dated August 28, 2018 – BCUC Information Request No. 1 to Delta School District
A-8	Letter dated October 31, 2018 – BCUC Request for Submissions on Further Process
A-9	Letter dated November 30, 2018 – BCUC Order G-228-18 issuing Regulatory Timetable with Reasons for Decision
A-10	Letter dated February 11, 2019 – BCUC Order G-31-19 issuing a Regulatory Timetable with Reasons for Decision

A-11 Letter dated February 15, 2019 – BCUC Order G-36-19 issuing an amended Regulatory Timetable with Reasons for Decision

A-12 Letter dated March 6, 2019 – BCUC request for clarification of Delta School District submission on Phase-in of proposed Cost of Service Rate

COMMISSION STAFF DOCUMENTS

A2-1 Letter dated August 28, 2018 – British Columbia Utilities Commission Staff Submission

APPLICANT DOCUMENTS

B-1 **FORTISBC ALTERNATIVE ENERGY SERVICES INC. (FAES)** Letter dated February 8, 2018 - 2018/2019 Revenue Requirements and Cost of Service Rates Application for the Thermal Energy Service to Delta School District No. 37

B-1-1 Letter dated June 13, 2018 – FAES Submitting Evidentiary Update to the Application

B-2 Letter dated April 25, 2018 – FAES Submitting Comments on DSD's Request for Regulatory Timetable Extension (Exhibit C1-2)

B-3 Letter dated June 13, 2018- FAES Submitting Response to DSD's Information Request No. 1

B-3-1 Letter dated June 13, 2018- FAES Submitting Response to DSD's Information Request No. 1 with Attachment 2.7b

B-4 Letter dated June 13, 2018- FAES Submitting Response to BCUC Information Request No. 1

B-4-1 **CONFIDENTIAL** - Letter dated June 13, 2018- FAES Submitting Confidential Responses to BCUC Information Request No. 1

B-5 Letter dated August 15, 2018 – FAES Submitting Confidentiality Declaration and Undertaking Form

B-6 Letter dated August 31, 2018 - FAES Submitting Information Request No. 1 on DSD Evidence

B-7 Letter dated October 11, 2018 – FAES Submitting Rebuttal Evidence

B-8 Letter dated November 8, 2018 – FAES Submitting Response to DSD Information Request No. 1 on Rebuttal Evidence

B-8-1 **CONFIDENTIAL** - Letter dated November 8, 2018 – FAES Submitting Confidential Attachment 7.1 to Response to DSD Information Request No. 1 on Rebuttal Evidence

B-9 Letter dated November 13, 2018 – FAES Submission on Further Process

B-10 Letter dated November 23, 2018 – FAES Reply Submission to DSD regarding Further Process

B-11 Letter dated February 3, 2019 – FAES Submitting Response to DSD Submitting Evidence (Exhibit C1-12)

INTERVENER DOCUMENTS

C1-1 **DELTA SCHOOL DISTRICT NO. 37 (DSD)** Letter dated April 25, 2018 – Request for Intervener Status by Dino Rossi and Erika Lambert-Shirzad

C1-2 Letter dated April 25, 2018 – DSD Submitting Request for Regulatory Timetable (Exhibit A-3) Extension

C1-3 Letter dated May 22, 2018 – DSD Submitting Information Request No. 1

C1-4 Letter dated June 14, 2018 – DSD Submitting Confidentiality Declaration and Undertaking

C1-5 Letter dated June 21, 2018 – DSD Submitting Extension Request to file Evidence

C1-6 Letter dated August 10, 2018 – DSD Submitting Evidence

C1-7 **CONFIDENTIAL** - Letter dated August 10, 2018 - DSD Submitting Confidential Evidence – Web cover letter only

C1-8 Letter dated September 26, 2018 – DSD Submitting Responses to BCUC IR No. 1

C1-9 Letter dated September 26, 2018 – DSD Submitting Responses to FAES IR No. 1

C1-10 Letter dated October 24, 2018 – DSD Submitting IR No. 1 with Appendices A and B on FAES Rebuttal Evidence

C1-11 Letter dated November 20, 2018 – DSD Submitting Response on Remaining Next Steps

C1-12 Letter dated February 1, 2019 – DSD Submitting Evidence (Reshape Strategies Report and MCW Consultants Ltd. Report)

C1-13 Letter dated February 4, 2019 – DSD Submitting Response to FAES Evidence Filing Objection (Exhibit B-11)

INTERESTED PARTY DOCUMENTS

D-1 Commercial Energy Consumers Association of British Columbia – April 27, 2018 Request for Interested Party Status

LETTERS OF COMMENT

E-1

FortisBC Alternative Energy Services Inc.

Application for Approval of the Fiscal 2018/2019
Revenue Requirements and Cost of Service Rates for the
Thermal Energy Service to Delta School District No. 37

LIST OF ACRONYMS

2017 JCI Report	Recommendations were made by JCI in its report issued in March 2017
AFUDC	Allowance for Funds Used During Construction
BAU	business as usual
BCUC	British Columbia Utilities Commission
CIAC	Contribution in Aid of Construction
Cleveland, ReShape	Will Cleveland of ReShape Strategies
Compliance Filing	On June 11, 2012, FAES filed its compliance filing to Order G-71-12
COS	Cost of Service
COS Rate	Cost of Service Rate
CPCN	Certificate of Public Convenience and Necessity
DDA	District Deferral Account
Delta SD, DSD	Delta School District No. 37
ESSAs, Service Agreements	Energy System Service Agreements
FAES	FortisBC Alternative Energy Services Inc.
FEI	FortisBC Energy Inc.
Geo-Energie	Geo-Energie Inc.
Geyer	witness, Frank Geyer

GHG	greenhouse gas
IRs	information requests
JCI	Johnson Controls International
JCLP	Johnson Controls L.P.
kWh	per kilowatt-hour
Market Rate, MR	“Market Rate”
MCW	MCW Consultants Inc.
O&M	operating and maintenance
Poole	Donald Poole
RDA	Rate Development Agreement
ROE	Return on Equity
RPE	Rocky Point Engineering Ltd.
TES	thermal energy system
TESDA	Thermal Energy Services Deferral Account
TLUP	Tax Loss Utilization Plan
UCA	*Utilities Commission Act*

Summary of Findings and Directives

This Summary is provided for the convenience of readers. In the event of any difference between the Findings and Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page
1.	**In light of the regulatory compact and the lack of specified constraints on the timing of any application for BCUC approval of a switch from the Market Rate to the COS Rate, the Panel finds it is just and reasonable to approve the Application by giving effect to FAES' right to trigger the switch at this time.**	15
2.	**As for the evidence offered by Geyer, the Panel rejects that evidence on the basis that it is irrelevant to the determination of the timing of the switch in light of the language in section 1.1(rr) and the Entire Agreement clause in section 11.8 of the RDA.**	15
3.	**Furthermore, based on a review of all of the evidence and for the reasons to be discussed later on in this Decision relating to a proposal for phasing in the COS Rate, the Panel is not persuaded that it would be in either FAES' or DSD's best interest for the switch to be further delayed beyond the aforementioned potential phase-in, and declines to do so.**	15
4.	**The Panel, based on a review of all of the relevant evidence finds as follows:** • **The RDA is based on a COS Rate design under which FAES anticipated it would be able to recover its cost of service, including an allowed ROE during the term of the RDA;** • **At the time they entered into the RDA, the parties expressly agreed to be bound by the Market Rate for an unspecified period of time;** • **FAES fully anticipated that it would be able to recover any difference between the COS Rate and the annual revenues from the service by accounting for the annual differences in the DDA and recovering the balance in the DDA over the remaining term of the RDA;** • **By the time of the CPCN Application, DSD was aware of and did not challenge FAES' expectation that the Market Rate would be in place for a period of at least two to five years, during which FAES did not anticipate applying for a switch to the COS Rate;** • **What would happen beyond that five-year period would depend on whether one or the other of the parties triggers the switch from the Market Rate to the COS Rate and the timing of that switch; and** • **The DSD has enjoyed a rate for the thermal energy service which has been lower than the COS Rate, the forecast Market Rate and the business as usual rate.**	16

5.	**Accordingly, in light of all of the above, the Panel rejects DSD's argument that the alleged collateral representations ought to be interpreted in such a way as to disallow FAES the remedy sought.**	17
6.	**Accordingly, in light of all of the above, the Panel rejects DSD's argument that it has established an alleged promissory estoppel which would preclude the BCUC from granting FAES the remedy sought.**	19
7.	**For these reasons and particularly in light of the CPCN Decision, the Panel finds the evidence offered by Poole and MCW irrelevant to the task of determining the timing and propriety of the proposed switch from the Market Rate to the COS Rate as stipulated in the RDA. The Panel further declines to "reassess" the CPCN on the basis that the Panel lacks jurisdiction to do so**.	27
8.	**As for DSD's request for a prudency review, the Panel finds that DSD has not provided adequate evidence to rebut the presumption of prudence and therefore denies DSD's request for a prudency review of the project capital costs.**	28
9.	**The Panel therefore finds that FAES has taken appropriate and reasonable steps to improve the optimization of the TES.**	29
10.	**The Panel further finds it is just and reasonable for FAES to recover its prudently incurred costs of providing service to DSD, including an allowed return on investment. These costs are clearly defined in section 1.1(d) of the RDA (the "Annual Cost Service") and, contrary to DSD's argument,[183] the Panel finds that there is sufficient evidence on the record, as detailed in Section 4.2 of this Decision, to show that the Annual Cost of Service amounts are reasonable and in accordance with the RDA.**	37
11.	**Should FAES decide in the future to add an amount in the Annual Cost of Service for indirect costs related to shared services charges from FEI to FAES or to change the TESDA allocation method, FAES is directed to file for approval of these changes with the BCUC prior to including the amounts in the Annual Cost of Service and COS Rate charged to DSD.**	37
12.	**The Panel finds the aforementioned scenario to be unjust and unreasonable under section 59(5) of the UCA.**	39
13.	**However, the Panel finds it reasonable to delay the switch to the COS Rate to July 1, 2019 to provide some accommodation for DSD's unique budgeting constraints. The Panel therefore declines FAES' application to make the COS Rate permanent effective July 1, 2018.**	39

[183] DSD Final Argument, p. 48.

14.	**Based on the above, the Panel orders the following:** **4. The switch from the Market Rate to the COS Rate is approved, effective July 1, 2019.** **5. The Market Rate, which was approved on an interim basis by Order G-77-18, is made permanent effective July 1, 2018.** **6. The difference between the actual Annual Cost of Service and the revenues collected for Fiscal 2018/19, plus an amount for AFUDC, is to be recorded in the DDA for recovery over the remaining years of the RDA term, beginning July 1, 2019.**	39
15.	To be clear, while the Panel has approved the one-year delay in implementation of the COS Rate to July 1, 2019, **the Panel finds the Annual Cost of Service and the COS Rate, which include the recovery of the DDA balance over the remainder of the RDA term, to be just and reasonable.**	40
16.	**In consideration of the above orders, the Panel directs FAES to file the following on or before May 31, 2019:** **4. Tariff pages reflecting the permanent Market Rate effective July 1, 2018; and** **5. An application for approval of the Fiscal 2019/20 Annual Cost of Service and COS Rate, which includes the information contained in Appendix A to the Application, updated for Fiscal 2019/20. FAES must include a breakdown and description of the forecast 2019/20 Annual Cost of Service and the financial schedules showing the actual 2012/13 through 2017/18 results, projected 2018/19 results and the forecast for 2019/20.**	40