Ms. Diane Roy  
Director, Regulatory Affairs - Gas  
FortisBC Alternative Energy Services Inc.  
16705 Fraser Highway  
Surrey, BC  V4N 0E8

Dear Ms. Roy:

Re: FortisBC Alternative Energy Inc.  
Project N. 3698677/Order G-74-12  
Application for a Certificate of Public Convenience and Necessity for  
the Approval for the PCI Marine Gateway Thermal Energy Project and Approval  
of Rates for Thermal Energy Service to PCI Developments Inc.

Further to Commission Order 74-12, which established a Regulatory Timetable with respect to the above noted Application,  
please provide a response to the enclosed Commission Information Request No. 1 by Wednesday, July 11, 2012.

Yours truly,

Erica Hamilton

TS/dg
Enclosure  
cc: Registered Interveners
1.0 Reference: Project Description
Exhibit B-1, Application, pp. 2-3, 27
System Capacity

According to pages 2 to 3 of the Application:

“While technically feasible to add future customers to this energy system, FAES will re-examine the expansion of the energy system to meet the needs of those customers once more detailed information is available for the adjoining sites. FAES will file a separate Application to the Commission if and when FAES intends to connect the TES to other developments.”

FAES states on page 27:

“The Project has been designed as a TES to accommodate the thermal energy needs at PCI’s Marine Gateway Development and will be constructed as a single phase. Pursuant to the City’s requirement, the energy system will contain a connection point to accommodate the transfer of energy between the PCI system and future developments. At present, no information is available to determine whether connecting future developments to the Project will be technically or economically feasible.”

1.1 Please clarify what is meant by “technically feasible to add future customers,” and if this entails the presence of additional capacity to meet this unknown future demand, or will extra capacity be added in the event of future customers joining?

2.0 Reference: The Applicant
Exhibit B-1, Application, p. 5
Relationship between FEI Inc. and FAES Inc.

Page 5 of the Application states: “FAES is a company that holds regulated assets, is incorporated under the laws of the Province of British Columbia, and is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), which in turn is a wholly-owned subsidiary of Fortis Inc. FAES maintains an office and place of business at 3700 2nd Avenue, Burnaby, BC V5C 6S4.

FAES is requesting the CPCN as the regulated public utility that will own and provide ongoing operation and maintenance of the system, as well as thermal energy.

“FAES has holdings which are regulated by the BCUC. FAES will obtain financing through FHI or indirectly through its ultimate parent, Fortis Inc.”
2.1 Please confirm that, irrespective of the presence of other regulated holdings within FAES, namely Dockside and the Delta SD, this is the first rate application to be brought by FAES Inc.?

2.2 Please confirm whether the office and place of business for FAES is shared with FEI?

3.0 Reference: The Applicant

Exhibit B-1, Application, p. 5; Order C-22-06, Appendix A, p. 1; KMI Terasen Acquisition Decision, November 10, 2005, pp. 1, 4, 6

Page 5 of the Application states that “FAES is a company that holds regulated assets, is incorporated under the laws of the Province of British Columbia, and is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), which in turn is a wholly-owned subsidiary of Fortis Inc.”

FAES Inc. was previously named Terasen Energy Services Inc. (TES Inc.)

Order C-22-06 describes TES Inc. as “a newly formed subsidiary of Terasen Inc. (which) is carrying on certain activities that previously had been handled by Terasen Utility Services Inc. (TUS). Commission Order No. G-52-06 approved the sale by Terasen Inc. of the common shares of TUS, which is now known as Corix Multi Utility Services Inc.”

The 2005 KMI Decision describes each of TGI, TGVI, TGW and TMUS as wholly-owned subsidiaries of Terasen (p. 1). TMUS operations included activities that are subject to BCUC regulation as well as non-regulated activities. The regulated activities of TMUS relate to the sale and distribution of natural gas, propane, and electricity. Its non-BCUC regulated activities are associated with property management, waste water and water treatment. (p. 4)

3.1 Please explain the history of TUS and TES, which activities were retained by TES after the sale of TUS, and the evolution of TES Inc into FAES Inc.

3.1.1 At the time of TMUS and its sale to Corix Utilities, what was the business and operational address of TMUS?

3.1.2 How many full time employees were employed by TMUS?

3.1.3 Following the sale of TMUS in 2006, when was the new TES Inc. created?

4.0 References: Human Resources Requirements

Exhibit B-1, Application, p. 6; AES Inquiry, Exhibit B-11, BCUC IR 1.67.2.1, p. 226; AES Inquiry, Exhibit B-11, BCUC IR 1.68.1, p. 228

Page 6 of the Application states that “FAES will not incur additional human resources to deliver this service to PCI. FAES will acquire services from FEI or another affiliate of FAES as described below in Section 6 Cost of Service and Rate design, and will be charged by FEI for those services pursuant to the transfer pricing method described in Section 6.2 Transfer Pricing.”

In response to BCUC IR 1.67.2.1 of the AES Inquiry, FEU responded that:
The activities currently undertaken by FAES relate to the projects owned and operated by FAES. These are TES projects that were developed prior to 2010. These activities involve customer care, billing and the operation and maintenance of equipment.

At the beginning of 2010, the responsibility for the development of new TES projects transferred from TES [FAES] Inc. to FEI (then TGI) in accordance with the approval provided in the FEI 2010-2011 RRA NSA. The primary responsibility for this activity is within the Energy Solutions and External Relations department within FEI, however, other departments also provide resources for this activity and charge time and/or expenses into the Thermal Energy Services deferral account if related to Thermal Energy Services projects.”

Page 228 of Exhibit B-11 in the AES Inquiry continues:

“At the beginning of 2010, six full time employees were transferred from Terasen Inc. to FEI in order to carry out the development of new TES within FEI in accordance with the FEI’s 2010-2011 RRA NSA (BCUC Order No. G-141-09). FAES has no employees. Employees who continue to manage the ongoing FAES business, cross charge their time accordingly to FAES. An application will be submitted to the Commission in due course once the issues in this Inquiry are settled for any FAES Inc. assets that will be transferred to FEI Inc. That application would address the financial situation of the projects to be transferred.”

4.1 Please provide a headcount and job description for the current employees of FAES Inc.

4.2 Please provide a headcount and job descriptions of FEI employees currently providing services to FAES Inc.

5.0 Reference: Project Background

Exhibit B-1, Application, p. 9

City of Vancouver’s Rezoning Conditions

FAES states that “The CoV approved PCI’s rezoning application in July of 2011. The approval contains a number of conditions regarding the energy system for the Development. The most significant of those conditions are the CoV’s requirements that 70% of the annual space heating and domestic hot water energy requirements for the Development are to be provided through renewable energy sources (which excludes electricity and natural gas according to the CoV), and that the system shall reduce the GHG emissions by a minimum of 50% relative to business as usual (which the CoV prescribed as a natural gas boiler system).

The closed-loop geo-exchange energy system that FAES seeks approval for in this Application meets the CoV’s rezoning requirements, and this was one of the reasons PCI received its rezoning for the Development.”

Appendix Q of the Application provides the July 19, 2011 Meeting Minutes of the Special Meeting of the Council of the City of Vancouver, which approved the rezoning application with conditions. On pp.23-23, the Renewable Energy Conditions 41 to 44 and 49 (under (b) Conditions of Approval of the Form of Development) provide that these conditions must be met “to the satisfaction of the General Manager of Engineering Services”. (Emphasis added)

On page 22, Conditions 41 and 42 refers to the Renewable Energy technology or Renewable Energy source as “sewage heat recovery or alternative.”

5.1 Given that FEI’s (and now FAES’s) preferred option (closed loop) was selected only after Council’s rezoning approval of July 19, 2011, have Conditions 41 to 44 and 49 noted above been met to the satisfaction of the General Manager of Engineering Services with respect to the selected closed loop geo-exchange energy system?

5.1.1 If so, please provide the material supporting this claim.

5.1.2 If not, please explain what steps still need to be taken by PCI and/or FAES to meet those conditions.

6.0 Reference: Definition of Business As Usual (BAU)
Exhibit B-1, Section 3.1 Project Background, p. 9; Section 3.5 Energy System Option Analysis, p. 14, p. 15, p.19, p. 23

On page 9 of the Application, FAES mentions the rezoning condition according to which “the system shall reduce the GHG emissions by a minimum of 50% relative to business as usual (which the CoV prescribed as a natural gas boiler system).” (Emphasis added)

Footnote 3 on page 14 states that “Business as Usual “BAU” as defined in the Rezoning Conditions in Appendix K is where residential units would otherwise be heated with electric resistance heat with natural gas combustion for heating ventilation air, common and non-residential spaces and domestic hot water, and through the use of chillers and cooling towers for any space cooling requirements.”

6.1 Please confirm that, in the CoV’s rezoning conditions, business as usual refers to the definition provided in Footnote 3.

On page 15, FAES states: “The CoV’s requirements resulted in a detailed analysis by FEI and PCI of potential energy systems that make use of renewable energy resources, and compared these options against a BAU scenario involving the use of natural gas boilers. The key documents that describe this analysis are as follows: …”

On page 19, FAES notes that “The results of the analysis was [sic] shown in the Table 3-6 below. The analysis also included the BAU option of a natural gas only system.” (Emphasis added)

6.2 Please confirm that the BAU scenario used as the baseline in the Screening Study dated June 28, 2010, i.e. the analysis referred to in the quote on page 19, refers to a natural gas only system.

6.3 Please provide the exact reference (quote and page number) from the Screening Study that defines the BAU used in that study.

6.4 If indeed the BAU refers to a natural gas only system, why was the BAU not defined from the start to match the BAU definition in the CoV’s rezoning conditions?

On page 23, FAES states: “The following table shows the capital costs, O&M costs, and GHG reduction estimates for the three options and the BAU case in Study #3: …”

6.5 Please clarify the definition of the BAU case used in Study #3 and provide the exact reference (quote and page number) from Study #3 to support this definition.
7.0 Reference: GHG Emission Savings of Closed Loop Option versus BAU
Exhibit B-1, Section 3.6.2 Proposed Alternative Meets the CoV's Conditions,
Table 3-10, p. 25; Appendix H, p. 11-12, Table 8 and Table 9
GHG Emissions Breakdown

Table 3-10: GHG Emissions

<table>
<thead>
<tr>
<th>Annual Heating and Cooling related GHG Emissions</th>
<th>Business As Usual (tCO(_2)e)</th>
<th>Closed Loop (tCO(_2)e)</th>
<th>GHG Reduction (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Building Boiler Natural Gas</td>
<td>1,481</td>
<td>586</td>
<td>60%</td>
</tr>
</tbody>
</table>

Source: DEC - Tech Memo 3 - Page 12-20 Table 9

Table 8: PCI Heating and Cooling Fuel Consumption Estimate

<table>
<thead>
<tr>
<th>PCI heating and cooling energy inputs</th>
<th>Business-as-Usual GJ (MWh)</th>
<th>PCI DESS Option GJ (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Building Boiler Natural Gas</td>
<td>27,770 (7.714)</td>
<td>10,213 (2.837)</td>
</tr>
<tr>
<td>Building Electric Resistance Electricity</td>
<td>7,798 (2.166)</td>
<td>-</td>
</tr>
<tr>
<td>Building Heat Pump/Chiller Electricity</td>
<td>1,692 (470)</td>
<td>6,926 (1,924)</td>
</tr>
<tr>
<td>DESS Heat Pump Electricity</td>
<td>-</td>
<td>2,444 (679)</td>
</tr>
<tr>
<td>Building Pumping Electricity</td>
<td>1,034 (287)</td>
<td>1,332 (370)</td>
</tr>
</tbody>
</table>

Table 9: PCI Heating and Cooling GHG Emissions Estimate

<table>
<thead>
<tr>
<th>Annual heating and cooling related GHG emissions</th>
<th>Business-as-Usual (tCO(_2)e)</th>
<th>PCI DESS Option (tCO(_2)e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Building Boiler Natural Gas</td>
<td>1,481</td>
<td>586</td>
</tr>
</tbody>
</table>

The following GHG emissions factors were used:
- Electricity = 22 tonnes CO\(_2\)e/GWh
- Natural Gas = 183.6 tonnes CO\(_2\)e/GWh

7.1 Please confirm that the BAU scenario described in Table 3-10 of the Application and Table 9 of DEC – Tech Memo 3 (Appendix H) does not refer only to “Building Boiler Natural Gas” but in fact refers to a scenario that comprises both electric resistance heat and natural gas combustion, as illustrated in Table 8 above.

7.2 Please revise Table 3-10 to provide the GHG emissions broken down by the energy input displayed in Table 8 for the BAU and Closed Loop options, as well as the total GHG emissions by option and the GHG reduction achieved with the Closed Loop option.

8.0 Reference: Load Analysis and Energy Demand Forecast
Exhibit B-1, Section 3.2, pp. 10-12

FAES states: “The PCI Marine Gateway Project encompasses approximately 81,000 m\(^2\) of developed floor area, as per the development permit application of September 2011. ...The total residential floor area is 30,783 m\(^2\). Commercial-Retail Units including theatres are located on the lower levels of the three towers, covering 46,877 m\(^2\)”
8.1 Please confirm that that the following table is correct. If not, please revise the table.

<table>
<thead>
<tr>
<th>Use</th>
<th>Floor Area (m²)</th>
<th>% of total floor area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>30,783</td>
<td>38%</td>
</tr>
<tr>
<td>Commercial-Retail Units</td>
<td>46,877</td>
<td>58%</td>
</tr>
<tr>
<td>Office</td>
<td>3,340</td>
<td>4%</td>
</tr>
<tr>
<td>Total</td>
<td>81,000</td>
<td>100%</td>
</tr>
</tbody>
</table>

FAES states: “The annual energy figures were based on the specific size and design of the three building structures and type of use among the residential, office and retail structures.”

8.2 Please provide the energy use intensity (EUI) factors by building archetype (e.g., residential high-rise concrete, office, retail) used to forecast the annual thermal energy load (10,300 MWh) and peak energy load (5.6 MW for heating and 3.5 MW for cooling) for the Marine Gateway Project. Please also provide the breakdown of the EUI by energy use (e.g., space heating, DHW and space cooling). Please complete the table below to answer this question.

<table>
<thead>
<tr>
<th>Use</th>
<th>Space Heat kWh/m²</th>
<th>Space Cooling kWh/m²</th>
<th>DHW kWh/m²</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercial-Retail Units</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Office</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other?</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

8.3 Which energy standard for buildings were the EUIs based on (e.g. ASHRAE 90.1-2007, other)?

8.4 In Table 3-1: Forecast Annual Energy Load, why is the category “Make Up Air (MUA) Heating-Grocery Store & Restaurants” or “Make Up Air (MUA) Cooling-Grocery Store & Restaurants” its own category and not included under “Retail”?

8.5 In Table 3-1: Forecast Annual Energy Load, why is the Residential Energy Load not at zero given that Residential Space Cooling is not provided to residential customers?

8.6 In Table 3-2, in which category is the peak energy load associated with DHW and with “Make Up Air (MUA) Heating-Grocery Store & Restaurants” included?

8.7 In Table 3-3, in which category is the peak energy load associated with Transformer Room and with “Make Up Air (MUA) Cooling-Grocery Store & Restaurants” included?

9.0 Reference: Vancouver’s EcoDensity Charter
Exhibit B-1, Section 3.3.1, p. 12

FAES states: “This policy required that when a site for a proposed rezoning exceeds 2 acres, rezoning applicants must produce a business case analysis performed by a qualified energy consultant to explore the viability of a campus or TES.”

9.1 Please explain the meaning of “campus” in the quote above.
10.0 Reference: Screening Study
Exhibit B-1, Section 3.5.2, pp. 18-21
Financial Analysis of Four Options

On p. 18, FAES states that “From the eight options described above, options with the lowest unit capital cost (four for PCI only and five options for the Node) were selected for further detailed analysis and screening.” (Emphasis added)

On p. 21, FAES further states that: “Although a closed-loop geo-exchange system was not among the options that was initially subject to further screening and analysis (due to higher capital costs as compared to the other four alternatives), DEC specifically noted that closed-loop systems should not necessarily be precluded from further analysis since they have benefits that may outweigh those of an open-loop systems including very low operating and maintenance costs and because there is limited to no water quality issues.” (Emphasis added)

10.1 Given the wide range of Unit O&M Cost for the eight options as presented in Tables 3-4 and 3-5 on page 18, why not taking into account both the capital costs and the O&M costs for the selection of options to be further analyzed in the Screening Study, in particular in light of the conclusion that a closed-loop geo-exchange system (i.e. ultimately the Preferred Option) should not necessarily be precluded from further analysis given its very low O&M costs? Who decided to only study options with the lowest unit capital costs in the original screening analysis and why.

10.2 Is it not true that, had the observation about the very low O&M costs of the closed-loop system been noted from the outset, the closed-loop system would have included in the further screening of the options?

On page 19, the results of the analysis are shown in Table 3-6, reproduced below for ease of reference.

<table>
<thead>
<tr>
<th>Option</th>
<th>Alternative Energy Source</th>
<th>Total Capital Cost ($000)</th>
<th>Total Annual O&amp;M Costs ($000)</th>
<th>Unit Annual GHG Emissions tCO2e/TJ (tCO2e/GWh)</th>
<th>First Year Rate $/GJ ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PCI BAU</td>
<td>None</td>
<td>3,765</td>
<td>693</td>
<td>63.9 (230)</td>
<td>25.0 (90)</td>
</tr>
<tr>
<td>PCI 1</td>
<td>Open Loop GHX</td>
<td>5,173</td>
<td>443</td>
<td>11.1 (40)</td>
<td>21.7 (78)</td>
</tr>
<tr>
<td>PCI 2</td>
<td>Wastewater</td>
<td>5,655</td>
<td>438</td>
<td>11.1 (40)</td>
<td>23.1 (83)</td>
</tr>
<tr>
<td>PCI 3</td>
<td>Biomass Thermal</td>
<td>7,827</td>
<td>325</td>
<td>6.5 (23)</td>
<td>26.6 (96)</td>
</tr>
<tr>
<td>PCI 4</td>
<td>Natural Gas Cogen</td>
<td>9,045</td>
<td>597</td>
<td>85.3 (307)</td>
<td>32.5 (117)</td>
</tr>
<tr>
<td>M&amp;C Node 1</td>
<td>None</td>
<td>5,002</td>
<td>1,166</td>
<td>63.9 (230)</td>
<td>23.1 (83)</td>
</tr>
<tr>
<td>M&amp;C Node 2</td>
<td>Low Temp Open Loop GHX</td>
<td>9,285</td>
<td>706</td>
<td>10.8 (39)</td>
<td>22.2 (80)</td>
</tr>
<tr>
<td>M&amp;C Node 3</td>
<td>High Temp Open Loop GHX</td>
<td>12,932</td>
<td>925</td>
<td>8.3 (30)</td>
<td>30.3 (109)</td>
</tr>
<tr>
<td>M&amp;C Node 4</td>
<td>Low Temp Wastewater</td>
<td>10,589</td>
<td>705</td>
<td>10.8 (39)</td>
<td>24.2 (87)</td>
</tr>
<tr>
<td>M&amp;C Node 5</td>
<td>High Temp Wastewater</td>
<td>12,766</td>
<td>908</td>
<td>8.3 (30)</td>
<td>30 (108)</td>
</tr>
<tr>
<td>M&amp;C Node 6</td>
<td>Biomass Thermal</td>
<td>13,598</td>
<td>555</td>
<td>6.6 (24)</td>
<td>27.8 (100)</td>
</tr>
<tr>
<td>M&amp;C Node 7</td>
<td>Natural Gas Cogen</td>
<td>15,408</td>
<td>1,023</td>
<td>85.3 (307)</td>
<td>33.3 (120)</td>
</tr>
<tr>
<td></td>
<td>WTE Thermal</td>
<td>31,398</td>
<td>753</td>
<td>73.6 (265)</td>
<td>259</td>
</tr>
</tbody>
</table>
10.3  For each of the five PCI options in Table 3-6, please provide the underlying thermal energy system capacity (in MW) that supports the calculation of “Total Capital Cost” for each option. Please provide details of the calculations.

10.3.1  If the underlying capacity (in MW) differs across the five options, please explain why.

10.4  For each of the five PCI options in Table 3-6, please provide the underlying annual energy demand (in MWh) that supports the calculation of “Total Annual O&M Costs” for each option. Please provide details of the calculations.

10.4.1  If the underlying annual energy demand (in MWh) differs across the five options, please explain why.

10.5  For M&C Node 7 in Table 3-6, please provide the unit for the First Year Rate of 259.

10.6  Please explain how the “First Year Rate” in Table 3-6 was calculated in relation to the 20-year levelized energy rate provided in Figure 3-1. Also provide the supporting calculations and assumptions.

10.7  Do the “First Year Rate” and “20-year Levelized Rate” include all costs, i.e. capital costs and O&M costs? If not, what do these rates include?

10.7.1  What would be the “First Year Rate” and “20-year Levelized Rate” for the closed-loop geo-exchange system?

11.0  Reference:  Study #2 Open Loop vs. Closed Loop Geo-Exchange
Exhibit B-1, Section 3.5.2, p. 22
Updated Costs

FAES states that “In terms of comparative costs, DEC’s updated capital cost estimates indicated that the open and closed loop systems are different by only $100 thousand. ... In addition, DEC also concluded that the updated O&M costs of the two sources at full build-out are very similar, with differences within 5%. Therefore, in its memo dated February 9, 2011, DEC concluded that “Based on the risks associated with the open-loop geo-exchange and the similarity in cost between the two sources, DEC recommends that Terasen proceed with closed-loop geo-exchange for the PCI Marine Development.”

11.1  Please provide a summary table of the two options (i.e. open loop and closed loop) and their respective Unit Capital Cost, Total Capital Cost, Unit O&M Cost and Total O&M Cost. Please indicate the energy capacity (in MW) and annual energy demand (MWh) assumptions for the calculations of Total Capital Cost and Total O&M Cost.

11.1.1  Please explain why the cost differentials between the open loop and closed loop options (both in terms of capital costs and O&M costs) have decreased so significantly between Screening Study and the Study #2.

Exhibit B-1, Section 3.5.3, pp. 23

FAES states that “Thus the sewer heat-recovery alternative was determined to have higher capital costs than the geo-exchange alternatives.”
Table 3-8 shows the capital costs, O&M costs and GHG reduction estimates for the three options and the BAU case in Study #3.

<table>
<thead>
<tr>
<th>Energy Option</th>
<th>Capital Cost $000</th>
<th>O&amp;M $000</th>
<th>Natural Gas Cost $000</th>
<th>Electricity Cost $000</th>
<th>Total $000</th>
<th>GHG Emission tCO₂e</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU</td>
<td>5,486</td>
<td>76</td>
<td>476</td>
<td>354</td>
<td>905</td>
<td>972</td>
</tr>
<tr>
<td>Open Loop GHX</td>
<td>6,057</td>
<td>49</td>
<td>61</td>
<td>252</td>
<td>362</td>
<td>275</td>
</tr>
<tr>
<td>Closed Loop GHX</td>
<td>6,106</td>
<td>41</td>
<td>61</td>
<td>274</td>
<td>376</td>
<td>279</td>
</tr>
<tr>
<td>Sewer Heat Recovery (SHT) (1)</td>
<td>6,317</td>
<td>48</td>
<td>61</td>
<td>234</td>
<td>343</td>
<td>271</td>
</tr>
</tbody>
</table>

12.1 Although the sewer heat recovery option has higher capital costs, is it not true that it also has the lowest annual O&M costs (including natural gas and electricity costs) of all the options displayed in Table 3-8?

12.2 Please calculate the life-cycle costs over 20 years for each of the options presented in Table 3-8 and provide the details for the calculations.

12.2.1 Which option has the lowest life-cycle costs over 20 years? Is this option the Preferred Option? If not, why not?

12.2.2 Which option has the highest life-cycle costs over 20 years?

FAES states that “Also, as a potential “first sewer heat recovery project” in Vancouver, this system would involve some added risk associated with adopting new technology and approvals. Although it is FAES’s understanding that Metro Vancouver has been examining heat-recovery potential from its sewer system, there are currently no existing CoV policies, contractual terms and connection cost information for sewer heat in the Lower Mainland. As a result, this option presented too much uncertainty for the developer and was rejected accordingly. Sewer heat recovery will continue to be explored with the CoV in the future for nearby developments should they materialize.” (Emphasis added)

12.3 Given that the Southeast False Creek Neighbourhood Energy Utility (SEFC NEU) began pre-commercial operations in December 2008 and in January 2012 the system became fully operational, delivering energy from its sewer heat recovery system to the buildings in the Olympic Village,¹ please explain how the energy system at Marine Gateway could have been a potential first sewer heat recovery project in Vancouver, had it selected sewer heat recovery as its preferred technology.

12.3.1 Could the lessons learned from the CoV’s experience with owning and operating the SEFC NEU not be shared with the proponents of the Marine Gateway Project, especially since FAES notes that “the sewage heat recovery option was further studied based on the CoV’s interest.” (p. 23)

On p. 7 in Appendix G, DEC states, under the Metro Vancouver Engagement section that “To our knowledge, Metro Vancouver has not reached an internal decision on requirements, including connection and energy charges for sewage heat extraction from their infrastructure.”

12.4 For the sewer heat recovery option, please clarify whether the energy system would have to connect to Metro Vancouver’s sewage system or that of the City of Vancouver.

13.0 Reference: Preferred Alternative for the Project
Exhibit B-1, Section 3.6.1, p.24
Benefits and Challenges of Options

FAES states that “Based on the above studies (Screening Study, Study #2 and Study #3), FEI concluded in consultation with PCI that a closed-loop geo-exchange system provides competitive costs in Capital and O&M and was the preferred system in view of the identification of risks associated with an open-loop geo-exchange system and the sewer heat recovery options.”

In Appendix G, DES provides the following comparative Table 2 (p. 5) of the benefits and challenges for the Sewage Heat Transfer and the Closed-Loop Geo-Exchange options.

![Table 2: Sewage Heat Transfer vs. Closed Loop Geoexchange](image)

13.1 Please revise the table above by adding the benefits and challenges of the Open-Loop Geo-Exchange technology.

14.0 Reference: Table 3-9 Summary of Energy Sourcing
Exhibit B-1, Section 3.6.2, p.25

Table 3-9 on page 25 indicates that the total annual cooling demand amounts to 15,178 GJ or 4,216 MWh (data from DES Tech Memo 3, dated March 21, 2012). Table 3-1 on p. 11 indicated that the total annual cooling demand is 6,444 GJ or 1,790 MWh (data is also from DES Tech Memo 3, dated March 21, 2012)

14.1 Please reconcile the data in the above-noted tables.
15.0 Reference: Overview of the System
Exhibit B-1, Section 4.3.1, p. 29
Ground Temperatures

FAES states that “Where waste heat needs to be rejected, as is the case for refrigerated cases, coolers, or computer servers, return water temperature is further elevated by the waste heat providing accelerated recharging of the ground.”

FAES also states “During periods of high heating demand or when ground temperatures are too low to provide heat source to the heat pumps, natural gas-fired boilers will provide back-up heat.”

15.1 Without waste heat recovery as described above, would there be a risk that the ground is not able to recharge its temperature fast enough? Please elaborate.

15.2 Please explain the circumstances that can result in the ground temperatures being too low to provide heat source to the heat pumps.

15.2.1 Is it possible that the natural gas-fired boilers would also be used to recharge the ground temperatures?

16.0 Reference: System Components
Exhibit B-1, Section 4.3.4.1, p. 31
Heat Pumps

FAES states that “The efficiency of a heat pump is expressed in terms of Coefficient of Performance (COP). A typical annual average COP of a heat pump is around 4. Each unit of electricity supplied to the heat pump allows the refrigerant to absorb 4 times as much energy from the evaporator. The total amount of energy that will have to be removed at the condenser to allow proper functioning of the heat pump is equivalent to 5 units of electricity. In essence, the heat generated by a heat pump is reduced to 1/5th of the electrical rate with very little GHG-emission (6.1 tCO2e/TJ).” (Emphasis added)

16.1 The above description seems to imply that one unit of electrical energy supplied to the heat pump will produce five units of heat energy out for a heat pump with a COP of “around” 4. Is this correctly stated?

16.2 Please provide the formula and definition of COP used by the heat pump industry.

16.3 Is FAES using a different definition and formula?

16.4 Do any of the energy, sizing, rate or GHG calculations, or competitive benchmarks use the heat pump COP factor in their equations?

16.4.1 If so, which COP definition and formula are used and should this be corrected?

16.5 What makes and unit size of heat pump are being considered for the project?

16.6 What is the published COP for the range of heat pumps being considered at the design conditions for this project? Please provide vendor datasheets if possible.
17.0 Reference: System Components
Exhibit B-1, Section 4.3.4.3, p. 32
Evaporative Cooler

FAES states that “An evaporative cooler may be required” (p. 32), “As the Project progresses into the design stage and heat-rejection from occupants is known, the cooler size will be determined more accurately.”

17.1 Does FAES know if an evaporative cooler will be required and it is a matter of accurate sizing or is there a possibility that an evaporative may or may not be required at all?

17.2 Please confirm if capital, operating and maintenance cost estimates include an evaporative cooler.

18.0 References: Metering and Billing
Exhibit B-1, Application, pp. 29, 34

According to page 29: “Heating, cooling and domestic hot water energy is measured for billing by FAES through energy meters located at the pipe risers serving each of the Development’s towers. Large consumers of energy at the CRU’s, such as food stores, restaurants, theatres, will additionally be provided with sub-meters to enable measurement of their individual energy consumption. Energy consumed in offices and residential units will be allocated according to proportion of total floor area.”

Page 34 of Application states: “Energy sub meters, owned by others, are installed at all major energy consuming CRU’s. They include food stores, restaurants, theatres, etc. Minor energy consuming CRU’s such as a newspaper store, dollar store, etc. may be combined to have one energy meter. Each office in the office tower will have the option to have its own meter. Energy metering of the residential towers will be implemented to separate rental units from Strata (owned) units.”

18.1 Please confirm that all sub-meters will be owned by other parties, and not FEI/FAES? If not, please provide additional details to clarify.

18.2 Will FAES be responsible for billing each of the commercial retail units (CRUs)?

18.3 Please provide the type and certification of the meters that will be used.

18.4 Does FAES foresee any challenges from Customers or Measurement Canada on the metering used for billing purposes? Please explain.

18.5 Are the meters able to be verified, recalibrated and recertified by approved independent persons? Will there be any planned verification testing of the meters?

18.6 Will there be any net energy metering that will be used for reconciliation of individual metering?

19.0 Reference: Service Agreements
Exhibit B-1, Section 4.6.3, p. 37
Service Agreements

FAES states that “Service Agreements will be signed by PCI and will then be assigned to four types of
customer groups: ...4. Retail complex – now with PCI and will be assigned to future tenants of the retail units.”

19.1 Will the Service Agreement – Commercial Retail be assigned to each future tenant of the retail units? If so, does this mean there will be more than one retail customer?

“Four types of customers will be served: 1) residential strata; 2) residential rental; 3) office complex; and 4) CRU tenants.” (p. 1)

19.2 Is there any planned infrastructure that will only or primarily be used to provide service to certain types of customers and not others? For instance, if FAES decides to build the Evaporative Cooler, would this piece of infrastructure be used only to serve the customers who have access to cooling?

19.3 What is FAES’ rationale for charging the same Rate for all customer types?

19.4 Has a cost-to-revenue ratio analysis been performed for each of the customer types?

19.4.1 If so, please provide the details and results of this analysis.

19.4.2 If no such analysis has been completed, on what basis is FAES to assume that all types of customers (residential, office, commercial) would incur the same cost of service?

20.0 Reference: 
Performance of Closed-Loop Geo-Exchange Technology
Exhibit B-1, Section 4.7.2, p. 38

FAES states that “The technology that FEI has selected for this Project is proven technology that has been applied in many cases where the heating and cooling of a building is performed by way of a geo-exchange system and has been applied in a number of projects that FEI, or its subsidiary FAES, currently own and operate.”

20.1 Please list all FEI’s/FAES’s projects in which closed-loop geo-exchange technology has been installed.

21.0 Reference: 
Stranded Asset Risk
Exhibit B-1, Section 4.7.4, p. 39

On page 39 FAES states that “However, if there is no renewal, then the Service Agreements require the customers to pay an amount that recovers the customer’s proportionate share of the “rate base value” of the assets in service. Therefore there is no risk of stranded assets.”

On page 37, FAES notes “The term of the Service Agreements will be 10 to 20 years for Retail Complex, depending on their lease terms with PCI, with no provision to terminate for reasons of convenience.”

21.1 Hypothetically, under difficult economic circumstances, would there be a risk for stranded assets in case of significant vacancies in the commercial retail units. Please elaborate.
22.0 Reference: Project Description
Exhibit B-1, Section 4.7, Application, p. 38-39
Capital Cost Estimate

“Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination...” (p. 39)

22.1 What is FAES’ rationale for assigning a construction contingency of 25 percent to direct capital?

22.2 What other projects of similar risk has FAES completed and what was the contingency assigned to these projects of similar risk?

23.0 Reference: Project Capital Cost Estimate
Exhibit B-1, Section 5.1, Application, p. 41
Development Costs

23.1 For the Tsawwassen Springs and Delta School District (DSD) TES projects, what percentage of total capital costs was categorized as development costs?

23.2 How do the development costs for Tsawwassen Springs and DSD compare to this Project? What are the reasons for the different percentages of development costs for each of these projects? Please explain in detail.

24.0 Reference: Project Capital Cost Estimate
Exhibit B-1, Section 5.5, Application, p. 48; Appendix T
Allowance for Funds Used During Construction

“AFUDC is estimated to be $305 thousand and is calculated at 6.66% of the estimated capital for the Project...” (p. 48)

24.1 Please provide a detailed breakdown by year of the AFUDC of $305 thousand.

24.2 Please explain and provide an example of how AFUDC is calculated in the electronic model (i.e. Appendix T).

24.2.1 Can you confirm that AFUDC has not been applied to the initial capital additions in 2015 and that it only applies to sustaining capital items?

25.0 Reference: Project Capital Cost Estimate
Exhibit B-1, Section 5.6, Application, p. 49
Inflation Rate

“Sustaining capital is forecast to inflate at 2% per year...” (p. 49)

25.1 Please provide FAES’ rationale for why it is appropriate to apply an inflation rate of 2 percent to this project?

25.2 Is the inflation rate of 2% in line with the BC CPI rate? Please provide supporting evidence of this.
26.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Application, p. 50; AES Inquiry, Exhibit B-11, BCUC IR 1.70.1, p. 236

Page 50 of the Application states:

“Once the rate is transitioned to cost of service, FAES will forecast annually the cost of service for providing thermal energy service to the development, based on the inputs described above, and the anticipated demand, to derive a thermal energy rate per kWh”;

In the AES Inquiry, FEI discussed the various fee structures used in FEI’s thermal contracts:

“The terms and conditions of pre-2010 FAES contracts and post-Jan. 1, 2010 FEI contracts are not materially different. All geo-exchange contracts are designed to fully recover the projects’ costs over the contract term. While the contracts to date have had fixed fees over the contract term with an annual adjustment for inflation, in the future and in response to customer demand, it is possible that fees will be based on thermal energy consumption. Both forms of contracts are designed to fully recover all capital-related costs, O&M, taxes and any other expenses directly attributable to the project, and an allowance for overheads over their contract terms.” (Exhibit B-11, BCUC IR1.70.1, p. 236)

26.1 What does FAES consider to be the benefits of an annual rate review process, compared to a formula based rate which is fixed for a longer period of time?

26.2 Did FAES/FEI consider any other rate model other than an annually reviewed cost of service rate for the Marine Gateway project? If so, what were they, and why does FEI/FAES think are their advantages and disadvantages for this and similar projects?

27.0 Reference: Transfer Pricing Policy
Exhibit B-1, Application, p. 51; AES Inquiry, Exhibit B-11, BCUC IR 1.72.4, pp. 240-241; AES Inquiry, Exhibit B-2, p. 112

FAES states on page 51 that “Subject to the outcome of the AES Inquiry, FAES will require services from its affiliate FEI in order to provide the service at the Development.”

Page 53 states that “FAES will use qualified contractors to carry out on-going maintenance and perform any repairs, if required. FAES will track the costs of any services performed using internal resources for maintenance services, such as 24-hour service responses via the internal order number for this service agreement within the Project Deferral Account. Included in the O&M are the estimated costs for the FEI’s employees, training, office equipment and supplies, subcontractors, maintenance and repair services, and preventative maintenance.”

FEI stated in Exhibit B-2 of the AES Inquiry, that “...FEI often plays the role of developer/project manager of the (thermal) proposal, bringing together the expertise from internal FEI groups and external suppliers and providers in order to deliver a successful energy solution. FEI believes that this model for providing thermal energy is appropriate and beneficial for the customer.” (p. 112)

In response to BCUC IR 1.72.4 of the AES Inquiry, FEI confirmed that they had been providing services to FAES (formerly TES Inc.) under the following corporate structure since 2007.
27.1 Please confirm which entity (FEI, FAES, another affiliate, or contractor), will be providing each of the following functions or services for FAES and the Marine Gateway project. Provide details where appropriate.

1. Overall project management
2. Operation & routine maintenance
3. Asset management
4. Project development
5. Contract administration
6. Customer contact, sales and development
7. Customer call-out/maintenance response
8. Billing function
9. Office buildings
10. Regulatory affairs
11. HR functions
12. Financial reporting functions
13. Shareholder services
14. Corporate Finance

27.2 Please confirm if there have been any changes to the corporate structure shown above, since the “reactivation” of FAES with the assignment of the Delta SD project?

28.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 5.6, Application, p. 51
Overview of Rate Design

“The rate will transition to cost of service in the fourth year and will include amortization of the deferral account.” (p. 51)
“Differences between the rates charged and the actual cost of service will be tracked in a deferral account and variances will either be recovered or credited in subsequent years.” (p. 51)

28.1 Please confirm that starting in Year 4 FAES will apply annually to the Commission for the cost of service rate.

29.0 Reference: Cost of Service and Rate Design
Section 6.4, Application, p.58 and Appendix T, Schedule 12
Rate Smoothing

FAES explains that “The annual amortization amounts are designed to create a manageable rate over the remaining years in the term.” (p.58)

29.1 Please explain Line 28 in Table 6-8 of the Application (Cost of Service (after Smoothing) Rate). What is the “smoothing” effect that is proposed in this cost of service calculation?

29.2 In Appendix T, Schedule 12, please explain the difference between Line 10 “Cost of Service (before smoothing) and Line 28 (Cost of Service (after Smoothing) Rate). Please confirm which rate FAES intends to charge the customer during the term of the agreement.

29.3 Please provide the reference contained in the disclosure statement (Appendix O) or Service Agreements (Appendix V) where the customer has agreed to this Rate Smoothing mechanism.

29.4 Please confirm and provide evidence which shows that the customer is, at minimum, aware of FAES’s forecast of the rate to be charged after the initial 3 years (the cost of service rate after smoothing).

30.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 6.1, Application, p. 51
Overview of Rate Design

“The rates developed for the first three years are mutually agreed upon rates of $0.109/kWh for 2015, $0.115/kWh for 2016 and $0.120/kWh for 2017.” (p.51)

30.1 For the first three years, how will variances between rates charged and the actual cost of service be treated? Will these variances accrue to the TESDA? Please explain.

31.0 Reference: Overview of Rate Design
Exhibit B-1, Section 6.1, p. 51
Variable Rate

FAES states that “the rates developed for the first three years are mutually agreed upon rates of $0.109/kWh for 2015, $0.115/kWh for 2016 and $0.120/kWh for 2017. The rate will transition to cost of service in the fourth year and will include amortization of the deferral account. Once the rate is transitioned to cost of service, FAES will forecast annually the cost of service for providing thermal energy service to the development, based on the inputs described above, and the anticipated demand, to derive a thermal energy rate per kWh.”
31.1 Please provide the rationale for choosing a 100 percent variable rate, as opposed to a rate design with both fixed and variable components.

31.1.1 Please provide the pros and cons of each rate design in the context of this Project.

32.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 6.2, Application, p. 51
TRANSFER PRICING

“...the proposal in this Application is to use FEI’s Transfer Pricing Policy (TPP), with the exclusion of the overhead charge and facilities fee, as the basis for cross charges between FEI and FAES. FAES confirms that this adjusted TPP methodology will remain in place until the Commission orders otherwise.” (p. 51)

32.1 In the recently issued Commission Order G-71-12, the Commission Panel stated that “...it is not convinced that the TPP is appropriate for cross charges between FEI and FAES...” Does FAES agree with the Panel’s view as stated in this decision?

32.1.1 Is FAES planning to make any amendments to the proposed cross charges for this application? Why or why not?

33.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 6.3.1, Table 6-1, Application, p. 52
Depreciation Expense

“The depreciation rates for sustaining capital and capitalized overhead reflect the average service lives of the equipment.”

33.1 Please explain and provide the calculation for how the 3.48 percent annual depreciation rate for sustaining capital and capitalized overhead was determined. Please show how this agrees with the average service lives of the equipment.

33.2 In the DSD project, the annual depreciation rate for Sustaining Capital and Capitalized Overhead was 2 percent. What is the rationale for using a 3.48 percent depreciation rate for Sustaining Capital and Capitalized Overhead in this project when the average service lives of the equipment in both the DSD and this project are very similar?

33.2.1 Is it not reasonable to expect that the depreciation rate would be very close if not the same to the rate used in the DSD project?

34.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 6.3.2, Table 6-2, Application, p. 52-53
Negative Salvage

34.1 Why was negative salvage not included in the Tsawwassen Springs and DSD cost of service calculations?

34.2 Please provide a detailed cost breakdown of the forecasted removal costs of the following equipment:
• Pumps, Heat Pumps and Exchange Equipment of $240.2 thousand
• Boilers high CCA of $15.5 thousand
• Structures – Cooling Towers of $21.8 thousand
• Loop Field (Ground Source Heat Exchanger) of $22.5 thousand

35.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 6.3.3, Application, p. 53
O&M Expense & Allocation of Overhead

“The cost of service each year will include the actual O&M expenses that have been incurred in that year.” (p.53) [Emphasis added]

35.1 Given that rate-making is forward-looking, why does FAES refer to “actual” O&M expenses to be included in the cost of service?

35.2 If actual O&M expenses are being included in the cost of service, does this mean that actual costs are flowing through the TESDA? If so, what is FAES’ incentive to provide the best possible forecast of its cost of service at this time?

“The O&M amount of $102 thousand relates to regular routine maintenance and minor repairs as described in Tech Memo #3 Appendix H…” (p. 53)

35.3 Please provide a more detailed breakdown of the O&M costs of $102 thousand, including a description of what assets the costs relate to and how much of the costs relate to labour.

35.3.1 Please provide the cost breakdown in a format to the Gross Plant in Service tab in Appendix T (Schedule 9).

“FAES will track the costs of any services performed using internal resources for maintenance services, such as 24-hour service responses via the internal order number for this service agreement within the Project Deferral Account.” (p. 53) [Emphasis added]

35.4 Does FAES’ reference to the “Project Deferral Account” indicate that it plans on allocating costs to a separate deferral account other then the TESDA?

35.4.1 Would this Project Deferral Account be a subset of the TESDA, similar to the treatment of deferred costs in the DSD project?

“The forecast of overhead recovery represents 33% of total O&M, which is a larger share than any other TES currently approved by the BCUC…” (p. 53, Footnote 12)

35.5 What is FAES’ rationale for setting overhead recovery at 33 percent for the Project?

36.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 6.3.3, Application, p. 53; Appendix T, Schedule 9
O&M Expense & Allocation of Overhead

“The cost of service for the development includes annual amounts for ongoing operating and maintenance expense and overhead costs less capitalized overhead.” (p. 53) [Emphasis added]
36.1 Please clarify how FAES is treating capitalized overhead in the cost of service calculation. Per Appendix T, Schedule 9, it appears that capitalized overhead is being included as part of Gross Plant in Service, but the above statement indicates that capitalized overhead is not being included in cost of service.

37.0 Reference: **Cost of Service and Rate Design**  
Exhibit B-1, Section 6.3.3 and Table 6-3, Application, p. 53-54  
O&M Expense & Allocation of Overhead

“Other ongoing overhead costs attributable to managing the FAES business including contract administration, billing, customer support, shared services and recovery of a reasonable share of the TESDA balance are forecast at $51 thousand……” (p. 53)

37.1 Please provide a detailed breakdown of the Corporate Overheads/TESDA/MISC costs of $35,865 shown in Table 6-3.

37.2 It appears that FAES is planning to include a portion of the TESDA balance in O&M costs. Why has FAES decided to include a portion of the TESDA balance now as opposed to waiting until the TESDA Application has been filed with the Commission?

“In the fourth year, rates will be set according to the forecast cost of service in that year, including an amortization amount to start to recover the balance in the deferral account.” (p. 58)

37.3 Please clarify the above sentence from p. 58 of the application. Why would FAES start recovering the TESDA in Year 4? Does this statement not seem to conflict with the statement quoted above from p. 53 of the application, which appears to be indicating that the TESDA will be incorporated in the cost of service starting in Year 1?

37.4 Please clearly state what year FAES plans to start recovering the TESDA and why.

38.0 Reference: **Cost of Service and Rate Design**  
Exhibit B-1, Section 6.3.3, Application, p. 54  
O&M Expense & Allocation of Overhead

“FAES will track the costs of any services performed using internal resources for maintenance services, such as 24-hour service responses via the internal order number for this service agreement within the Project Deferral Account.” (p. 53)

38.1 Please explain in more detail the process for tracking internal resources assigned to a certain project.

38.2 Has FAES included a standby charge in the O&M costs for the use of the 24-hour service response capability? If not, please explain why not.

38.3 Please confirm if the “Project Deferral Account” refers to the TESDA or to a separate deferral account.

38.4 Please provide a complete list of services to be provided by existing gas distribution resources and infrastructure.
39.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 6.3.3.1, Application, p. 54
Capitalized Overhead

“FAES does not believe capitalized overhead should be applicable to this project.” (p.54)

“The methodology of calculating capitalized overhead at 14 percent of gross project operating and
maintenance costs is accepted at this time for the Delta School District project, but only for the years
where capital additions or capital replacements are expected.” (Commission Order G-71-12, Directive
1.a.) [Emphasis added]

“For future TES applications, FEI/FAES is to provide a more fulsome discussion on the implications of
capitalized overhead and whether this should be embedded in the transfer pricing policy or whether a
more systematic approach may be more appropriate.” (Reasons to Order G-71-12)

39.1 Based on the recent DSD in Commission Order G-71-12, is FAES now in agreement that
capitalized overhead is applicable to the Project? If not, why not?

39.2 Please revise the calculation of capitalized overhead so that it is only applied in years where
there are capital additions or capital replacements.

39.3 Please discuss the implications of capitalized overhead and whether capitalized overhead should
be embedded in FAES’ TPP or whether there is a more appropriate approach.

40.0 Reference: Cost of Natural Gas and Electricity
Exhibit B-1, Section 6.3.4, pp. 54-55

FAES states: “FAES is treating the natural gas and electricity costs as direct flow-throughs to the Rate in
the 20 year analysis except for the first three years, which has a smoothed Rate (as further described in
Section 6.5 Annual Rate Based on Forecast Cost of Service and Energy Demand). FAES has used
prevailing published tariffs and forecasts to the best of FAES’s knowledge as of April 2012 so that Rates
can be established for this Application. The forecast for natural gas is based on the commodity price
forecasts published by the GLJ Petroleum Consultants and electricity forecast is based on the current
BC Hydro Revenue Requirements.”

40.1 Please clarify which natural gas rate schedule FAES will apply to each type of customer and how
these rate schedules compare to the commodity price forecasts published by the GLJ Petroleum
Consultants.

41.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 6.3.5.1, Application, p. 55
Capital Structure and Return on Equity

“FAES believes that the appropriate rate of return for this Project is determined by using a capital
structure equivalent to that of the benchmark utility (40% equity and 60% debt), with a 50 basis points
equity risk premium over the benchmark ROE.” (p. 55)

41.1 Why does the TESDA not eliminate/reduce the business risk of the Project and therefore lower
the equity risk premium?
41.2 Please indicate whether FAES agrees with each description provided in Table 1. For any risk factor description with which FAES disagrees in Table 1, please explain why FAES disagrees. Please provide the responses in the same table format as Table 1. If references are used, please cite them.

**Table 1: Risk factor by Risk Factor Comparative Description**

<table>
<thead>
<tr>
<th>Risk Factor</th>
<th>FEI Natural Gas Class of Service</th>
<th>FEI Delta School District Project</th>
<th>FAES PCI Marine Gateway Project</th>
<th>Corix UniverCity</th>
<th>Dockside Green Energy</th>
<th>River District Energy Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital structure (debt/equity ratio)</td>
<td>60/40 (actual)</td>
<td>60/40 (actual)</td>
<td>60/40 (actual; proposed)</td>
<td>Deemed 60/40</td>
<td>Deemed 60/40</td>
<td>Deemed 60/40</td>
</tr>
<tr>
<td>Equity Risk Premium</td>
<td>N/A</td>
<td>0 to somewhat higher; Final equity premium not yet approved</td>
<td>50 bps (proposed)</td>
<td>50 bps (approved)</td>
<td>100 bps (approved)</td>
<td>50 bps (approved)</td>
</tr>
<tr>
<td>Technology risk/system performance risk associated with chosen technologies</td>
<td>Natural Gas: proven technology</td>
<td>High-efficiency condensing boilers: proven technology; Ground source heat pumps: less established technology</td>
<td>Geo-exchange loop field system: proven technology that has been applied in a number of FEI/FAES projects</td>
<td>Natural Gas boilers: proven technology</td>
<td>Biomass Gasification: innovative technology; Natural Gas boilers: proven technology (while DGE not yet on biomass, the Commission approved the technology)</td>
<td>Natural Gas boilers: proven technology</td>
</tr>
<tr>
<td>Fuel risk (cost &amp; availability)</td>
<td>Natural gas: Low-medium</td>
<td>Natural gas and electricity: low-medium; Heat from ground: none</td>
<td>Free energy from ground: no risk for fuel cost and availability</td>
<td>Natural gas fuelled energy centre: Low-medium Alternative renewable energy source: not approved yet and thus not relevant</td>
<td>Biomass: medium-high; Natural Gas: low-medium Alternative renewable energy source: not approved yet and thus not relevant</td>
<td>Natural gas fuelled energy centre: Low-medium</td>
</tr>
<tr>
<td>Customer base (e.g., diversity, certainty, growing, declining)</td>
<td>Established and diverse customer base but very slow growth</td>
<td>One known customer; no risk</td>
<td>Several known customers; low risk</td>
<td>Greenfield utility; uncertainty related to timing of full build-out</td>
<td>Greenfield utility; uncertainty related to timing of full build-out</td>
<td>Greenfield utility; uncertainty related to timing of full build-out</td>
</tr>
<tr>
<td>Default risk of customer</td>
<td>Minimal</td>
<td>Minimal as SD has budget constraints as well</td>
<td>Minimal</td>
<td>Minimal</td>
<td>Minimal</td>
<td>Minimal</td>
</tr>
<tr>
<td>Property development risk</td>
<td>Medium to high: there are competing energy options</td>
<td>None, as not a new development</td>
<td>Low, sold out</td>
<td>Low: phased approach to capital deployment</td>
<td>Low: phased approach to capital deployment</td>
<td>Low: phased approach to capital deployment</td>
</tr>
<tr>
<td>Developer/customer connection risk</td>
<td>Medium to high: due to building stock changes and competitive energy sources</td>
<td>None, as one known customer with existing sites</td>
<td>Low, as several known customer</td>
<td>Low: mandatory connection</td>
<td>Low: mandatory connection</td>
<td>Low: mandatory connection</td>
</tr>
<tr>
<td>Risk Factor</td>
<td>FEI Natural Gas Class of Service</td>
<td>FEI Delta School District Project</td>
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<tr>
<td>7 Load forecast uncertainty</td>
<td>Minimal in the short-term, as mature utility with deferral account; somewhat higher in the long term</td>
<td>Low, as established energy load</td>
<td>None, as energy consumption estimate has no bearing on Rate</td>
<td>Inherent uncertainty in load forecast</td>
<td>Inherent uncertainty in load forecast</td>
<td>Inherent uncertainty in load forecast</td>
</tr>
<tr>
<td>8 Utility size</td>
<td>Large and mature utility</td>
<td>Project is carried out by separate corporate entity</td>
<td>Project is carried out by separate corporate entity</td>
<td>Small development-specific utility</td>
<td>Small development-specific utility</td>
<td>Small development-specific utility</td>
</tr>
<tr>
<td>9 Initial construction cost risk</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
</tr>
<tr>
<td>10 Future construction cost risk</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
<td>Depends on the nature of the individual project</td>
</tr>
<tr>
<td>11 Operating cost risk</td>
<td>Minimal as revenue requirement application to recover cost</td>
<td>Minimal as mechanism in place to recover costs</td>
<td>Minimal as mechanism in place to recover costs</td>
<td>Minimal as mechanism in place to recover costs</td>
<td>Minimal as mechanism in place to recover costs</td>
<td>Minimal as mechanism in place to recover costs</td>
</tr>
<tr>
<td>12 Public acceptance risk</td>
<td>Medium, as natural gas is an established and widely used technology but public perceives it as less than clean</td>
<td>Low, seen as a green alternative</td>
<td>Low as seen as a green alternative</td>
<td>Low, seen as a green alternative</td>
<td>Low, seen as a green alternative</td>
<td>Low, seen as a green alternative</td>
</tr>
<tr>
<td>13 Fixed/variable rate design</td>
<td>15% fixed / 85% variable</td>
<td>100% variable</td>
<td>100% variable</td>
<td>60% fixed / 40% variable</td>
<td>50% fixed / 50% variable</td>
<td>66% fixed / 34% variable</td>
</tr>
<tr>
<td>14 Levelized approach to rates</td>
<td>No</td>
<td>No, transitional market rate and deferral account</td>
<td>Only in first three years, then transition to cost of service</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>15 Financial risk</td>
<td>Low-medium: appropriate stand-alone financing structure for capital markets</td>
<td>Medium</td>
<td>Low-medium</td>
<td>Low-medium: subsidiary of parent utility company</td>
<td>Low-medium: subsidiary of parent utility company</td>
<td>Low-medium: subsidiary of parent developer company</td>
</tr>
<tr>
<td>16 Competitive challenges</td>
<td>Competitive with electricity and competition from alternative energy providers</td>
<td>Other TES providers and electricity</td>
<td>Other TES providers and electricity</td>
<td>Other utilities and electricity</td>
<td>Other utilities and electricity</td>
<td>Other utilities and electricity</td>
</tr>
<tr>
<td>17 Provincial climate change and energy policies</td>
<td>Encourage reduction of fossil fuels usage to reduce GHG emissions and lower energy use</td>
<td>Favourable government policies</td>
<td>Favourable government policies</td>
<td>Favourable government policies</td>
<td>Favourable government policies</td>
<td>Favourable government policies</td>
</tr>
<tr>
<td>18 Regulatory uncertainty</td>
<td>Low to Medium, as uncertainty exists for service offerings within the natural gas class of service</td>
<td>Medium risk: new, uncertainty, scrutiny and not streamlined</td>
<td>Medium risk: New, uncertainty, scrutiny and not streamlined</td>
<td>Medium risk: New, uncertainty, scrutiny; alternative energy centre not yet approved</td>
<td>Medium risk: New, uncertainty, scrutiny; alternative energy centre not yet approved</td>
<td>Medium risk: New, uncertainty, scrutiny; alternative energy centre not yet approved</td>
</tr>
</tbody>
</table>
41.3 Please find in Table 2 below an evaluation of the risk level by risk factor for the Project as the benchmark (column 1), to which columns 2 to 6 are compared, on a risk-factor-by-risk-factor basis.

41.4 Please indicate if FAES agrees with the comparative risk assessment for each risk factor provided in Table 2. For any risk-level assessment with which FAES disagrees in Table 2, please explain why FAES disagrees.

Table 2: Comparative Evaluation of Risk Factors

<table>
<thead>
<tr>
<th>Risk Factor</th>
<th>FAES PCI Marine Gateway Project</th>
<th>FEI Natural Gas Class of Service (Benchmark)</th>
<th>Delta School District Project</th>
<th>Corix UniverCity</th>
<th>Dockside Green Energy</th>
<th>River District Energy Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Technology risk</td>
<td>Low</td>
<td>Lower</td>
<td>Lower (natural gas boiler) or higher (ground source heat pumps)</td>
<td>Lower</td>
<td>Higher</td>
<td>Lower</td>
</tr>
<tr>
<td>2 System performance risk associated with chosen technologies</td>
<td>Low risk as no consequence if poor performance</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
<tr>
<td>3 Fuel risk (cost and availability)</td>
<td>No risk, as free energy from ground</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
<tr>
<td>4 Customer base (e.g., diversity, certainty, growing, declining)</td>
<td>No risk, as several known customers and sold out</td>
<td>Higher</td>
<td>Similar</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
<tr>
<td>5 Default risk of customer</td>
<td>Minimal risk</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
</tr>
<tr>
<td>6 Property development risk</td>
<td>Low risk</td>
<td>Higher</td>
<td>No risk, as not a new development</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
</tr>
<tr>
<td>7 Developer/customer connection risk</td>
<td>No risk, as several known customers and sold out</td>
<td>Higher</td>
<td>Similar</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
<tr>
<td>8 Load forecast uncertainty</td>
<td>No risk, as energy consumption estimate has no bearing on Rate</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
<tr>
<td>Risk Factor</td>
<td>FAES PCI Marine Gateway Project</td>
<td>FEI Natural Gas Class of Service (Benchmark)</td>
<td>Delta School District Project</td>
<td>Corix UniverCity</td>
<td>Dockside Green Energy</td>
<td>River District Energy Project</td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>---------------------------------</td>
<td>---------------------------------------------</td>
<td>-------------------------------</td>
<td>-----------------</td>
<td>-----------------------</td>
<td>------------------------------</td>
</tr>
<tr>
<td>9. Utility size</td>
<td>Low, as FEI executing project</td>
<td>Similar</td>
<td>Higher, as separate entity will carry out the project</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
<tr>
<td>10. Initial construction cost risk</td>
<td>Low risk</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
<tr>
<td>11. Future construction cost risk</td>
<td>Low risk</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
<tr>
<td>12. Operating cost risk</td>
<td>Minimal risk: mechanism in place to recover costs</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
</tr>
<tr>
<td>13. Public acceptance risk</td>
<td>Low risk</td>
<td>Higher</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
</tr>
<tr>
<td>14. Fixed/variable rate design</td>
<td>Fully variable</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
<tr>
<td>15. Levelized approach to rates</td>
<td>No: higher risk</td>
<td>No: higher risk</td>
<td>No: higher risk</td>
<td>Yes: similar</td>
<td>Yes: similar</td>
<td>Yes: similar</td>
</tr>
<tr>
<td>16. Financial risk</td>
<td>Low, as FEI executing project</td>
<td>Similar</td>
<td>Medium: separate entity will carry out the project</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
</tr>
<tr>
<td>17. Competitive challenges</td>
<td>Low as the Strata Corporation is obliged through contract to take thermal energy from FAES</td>
<td>Higher, as natural gas has competitive challenges with respect to other energy sources</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
</tr>
<tr>
<td>18. Provincial climate change and energy policies</td>
<td>Low risk</td>
<td>Higher</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
</tr>
<tr>
<td>19. Regulatory uncertainty</td>
<td>Medium risk</td>
<td>Lower</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
<td>Similar</td>
</tr>
<tr>
<td>20. Business development risk</td>
<td>Minimal risk</td>
<td>Similar</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
<td>Higher</td>
</tr>
</tbody>
</table>

42.0 Reference: Cost of Service and Rate Design

Exhibit B-1, Section 6.3.5.2, Application, p. 55

Cost of Debt

“FAES is directed to re-calculate its deemed cost of debt rate based on BBB-rated entities operating specifically in the TES class of service...however...the Panel would accept BBB-rated distribution utilities, such as AltaGas Ltd. and Emera Inc., as proxies for the TES class of service.” (Reasons for Decision to Order G-71-12) [Emphasis added]

42.1 Based on Commission Order G-71-12 (Delta School District Decision), will FAES be amending the cost of debt of 5.91 percent? If not, why not?
FAES states that “To ensure the competitiveness of the thermal energy rates, for the first three years the rates were set at a mutually agreed rate that was developed based on recent guidance from the Commission Order G-2-12 where the Commission Panel approved using a benchmark based on BC Hydro residential electricity rates at 50 percent Tier 1 and 50 percent Tier 2 plus a 5% to 10% premium for the basic charge.”

The Reasons for Decision in Appendix A to Order G-2-12 state: “The Commission Panel in its Decision dated December 19, 2011 (Order C-14-11) accepted that a premium of up to 10 percent above the benchmark electricity rate may be justified when establishing rates for the District Energy Utility (DEU) to be constructed and operated by River District Energy Limited Partnership (RDE). After finding the RDE’s forecast of BC Hydro’s 2012 residential electricity rates and the assumed weighted average consumption mix of 50 percent Tier 1 and 50 percent Tier 2 to be reasonable, the Commission Panel considered that the initial 2012 rate for RDE should be no less than the blended $87.97 per MWh benchmark rate.” (Emphasis added)

In the December 19, 2011 Decision, the Commission agreed with RDE that the District Energy Utility (DEU) was well positioned to deliver additional intangible benefits to consumers and thus accepted that a premium of up to 10 percent above the benchmark electricity rate may be justified when establishing rates for the DEU. (p. 28) On page 30 of that Decision, the Commission found reasonable RDE’s forecast of BC Hydro’s 2012 residential electricity rates and its assumed weighted average consumption mix of 50% Tier 1 and 50% Tier 2. Applying those weights to the Tier 1 and Tier 2 rates resulted in a blended rate per MWh of $87.97. The Commission further noted that this blended rate does not reflect BC Hydro’s Basic Charge, and is therefore somewhat understated. Then, the DEU premium of up to 10% is added to the electricity benchmark. (Emphasis added)

43.1 Please confirm that FAES understands that, in the case of the River District Energy Decision, the electricity benchmark, based on a forecast of BC Hydro’s residential rates, did not take into account the Basic Charge, and that the premium of up to 10 percent was added to this electricity benchmark to recognize the additional intangible benefits that a district energy system can deliver.

43.2 In order to follow the guidance from Commission Order G-2-12 and the December 19, 2011 RDE Decision in the area of benchmarking, please provide a revised Table 6-6: Benchmark Rates without the “10 percent Basic Charge added as per BCUC Order G-141-11.”

Table 6-7: Rate Escalations Forecast is reproduced below for ease of reference.

| Table 6-7: Rate Escalations Forecast |
|-------------------------------------|---------|---------|---------|---------|---------|---------|
| BCH Electricity Forecast (50% Step 1 Residential & 50% Step 2) | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| $0.993 | $0.999 | $0.104 | $0.109 | $0.115 | $0.120 |
| BCH Rate Escalation based on Commission Interim Decision on rates increase on fiscal 2013 in Order G-6-17-12. After Fiscal 2013, used escalation assumptions at 3% + rate rider at 2%. | 7.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |

43.3 For clarity purposes, in Table 6-7, when FAES refers to the year 2012 for example, does it mean fiscal year 2013, which, in the case of BC Hydro, would mean rates as of April 1, 2012?
On May 22, 2012, the Lieutenant Governor in Council, by Order in Council No. 314, issued Direction No. 3 to the Commission, pursuant to section 3 of the Act. Direction No. 3 requires the Commission to issue the final orders to BC Hydro as requested in the Amended Application except for certain adjustments specifically noted in Direction No. 3. Directive 1 of Commission Order G-77-12, dated June 13, 2012, approved the following rate increases, which will be applied to the residential tariff:

- The F2012 rate increase of 8.0 percent effective May 1, 2011, and the F2013 rate increase of 3.91 percent, effective April 1, 2012;
- The F2014 rate increase, effective April 1, 2013, that is on average 1.44 percent higher than F2013 rate, subject only to a Commission order under section 44.2 of the Act respecting BC Hydro’s F2014 expenditures on DSM;
- The DARR for F2012 at 2.5 percent is approved. The DARR for F2013 and F2014 is to be set at 5 percent. The DARR shall remain at 5 percent until the Commission orders a change.

43.4 Please complete the following table. For Line b “BCH Rate Escalation,” please use BC Hydro’s rate increases as approved by Commission Order G-77-12. The 10 percent Premium is added last to reflect Order G-2-12 and the River District Decision dated December 19, 2011.

<table>
<thead>
<tr>
<th></th>
<th>BCH Electricity Forecast (50% Step 1 Residential &amp; 50% Step 2)</th>
<th>F2013</th>
<th>F2014</th>
<th>F2015</th>
<th>F2016</th>
<th>F2017</th>
<th>F2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>a</td>
<td>BCH Rate Escalation Based on Order G-77-12</td>
<td>[insert % rate increase for F2014]</td>
<td>[insert % rate increase for F2015]</td>
<td>[insert % rate increase for F2016]</td>
<td>[insert % rate increase for F2017]</td>
<td>[insert % rate increase for F2018]</td>
<td>Not applicable</td>
</tr>
<tr>
<td>b</td>
<td>10% Premium (line a * 0.10)</td>
<td>$0.085 / kWh</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>c</td>
<td>Energy Rate for Marine Gateway (line a + line c)</td>
<td>$0.093</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

44.0 Reference:  Thermal Energy Rate – Fourth Year and Beyond
Exhibit B-1, Section 6.5, p. 58; Appendix T, Schedule 11, Line 5; Schedule 12, Line 14

FAES states that “In the fourth year, rates will be set according to the forecast cost of service in that year, including an amortization amount to start to recover the balance in the deferral account. The annual amortization amounts are designed to create a manageable rate over the remaining years in the term.”

44.1 Please confirm that Line 5 in Schedule 11, Appendix T, labelled “Gross additions” to the deferred charge, indicates that from 2018 to 2021, FAES will still under-recover each year and put the difference between the annual revenue and the cost of service into the deferral account.

44.1.1 If confirmed, please explain the statement that FAES will start recovering the balance in the deferral account in the fourth year.
44.2 Please explain in plain language how FAES has calculated the “Refund of Variance Account” in Line 14, Schedule 12, Appendix T.

45.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Section 6.6, Application, p. 59
Deferral Mechanism to “True Up” Actual Cost

“FAES will record any difference between the revenues and the cost of service in a deferral account in the first year of the contract term and in each subsequent year through the term of the service contracts.” (p. 59)

45.1 Would FAES agree that the overall risk level for the Project is “low” due to the ability to allocate costs to the Thermal Energy System Deferral Account (TESDA)? If FAES does not agree, please explain why.

45.2 Please confirm that “a deferral account,” as stated above, is the TESDA.

45.3 If FAES plans to record differences between the revenues and cost of service in a deferral account, what incentive does FAES have to accurately forecast its cost of service at this time?

45.4 In the DSD application, FEI proposed a separate SD37 deferral account which was a subset of the overall TESDA. Please explain why a similar approach was not taken with the PCI Marine Gateway project (i.e. a subset of the overall TESDA)?

45.5 Please provide the current balance of the TESDA. Please list all the cost categories, along with their respective balances, that are currently held in the TESDA.

46.0 Reference: Cost of Service and Rate Design
Exhibit B-1, Appendix T
O&M Expense & Allocation of Overhead

46.1 Given the high capital cost of this project, please explain why FAES did not perform a detailed lead-lag study to determine the appropriate level of cash working capital?

46.2 Please explain what circumstances would trigger a detailed lead-lag study as opposed to adopting the simplified method of using 12.5 percent of O&M (as in the case of DSD)?

47.0 Reference: Disclosure Agreement
Exhibit B-1, Appendix O

47.1 Please provide the excerpt for thermal energy costs contained in the Disclosure Statement.

48.0 Reference: Public Consultation
Exhibit B-1, Application, p. 62

FAES states: “FEI presented information about the energy system including how the system will utilize waste heat and allow for energy sharing to provide energy to the Development.”

48.1 Please describe and provide materials used to explain the term “energy sharing” and how this
works in a practical sense for the proposed project design.

48.2 What amount including percentage of the annual (space heating and domestic hot water) energy requirements for the Development is expected to come from energy sharing or recovery of waste heat?

49.0 Reference: Provincial Energy Policy Considerations
Exhibit B-1, Application, p. 64; Clean Energy Act, Section 2

BC Energy Objectives

FAES states: “Section 46 of the Utilities Commission Act requires the Commission to consider the applicable British Columbia energy objectives.” Then, FAES lists two BC energy objectives that the project supports:

To use and foster the development in British Columbia to support energy conservation and efficiency and the use of clean or renewable resources.

To reduce BC greenhouse gas emissions.

Section 2 of the CEA sets out British Columbia’s energy objectives.

49.1 Does FAES agree that the first objective above should instead read: (d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources?

49.2 Please describe the extent to which the Marine Gateway Project also supports the following BC energy objectives: (h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia; (i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently; and (j) to reduce waste by encouraging the use of waste heat, biogas and biomass.

50.0 Reference: Sensitivity Analysis
Exhibit B-1, Section 6.8, p. 60

FAES states that “As assumptions for the analysis, FEI seeded 8 separate variables for each year over the 20 years in the analysis using empirical data for each variable.”

50.1 Please elaborate on the Monte Carlo process described above.
Table 6-11 is recopied below for ease of reference.

<table>
<thead>
<tr>
<th>Percentiles</th>
<th>Thermal Energy Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>0.135</td>
</tr>
<tr>
<td>10%</td>
<td>0.146</td>
</tr>
<tr>
<td>20%</td>
<td>0.148</td>
</tr>
<tr>
<td>30%</td>
<td>0.150</td>
</tr>
<tr>
<td>40%</td>
<td>0.151</td>
</tr>
<tr>
<td>50%</td>
<td>0.152</td>
</tr>
<tr>
<td>60%</td>
<td>0.153</td>
</tr>
<tr>
<td>70%</td>
<td>0.154</td>
</tr>
<tr>
<td>80%</td>
<td>0.155</td>
</tr>
<tr>
<td>90%</td>
<td>0.157</td>
</tr>
<tr>
<td>100%</td>
<td>0.174</td>
</tr>
</tbody>
</table>

50.2 Please provide the measurement unit for the Thermal Energy Rate in Table 6-11

50.3 Please explain how to interpret a Thermal Energy Rate of 0.153.

FAES further states that: “The Monte Carlo results indicated that rates are competitive in all scenarios when compared to other thermal energy systems recently approved by the BCUC.”

50.4 By “all scenarios”, does FAES mean the 10 levelized rate scenarios presented in Table 6-11?

50.5 Please list all the other thermal energy systems recently approved by the BCUC and, for each of them, its 20-year levelized rate. Please provide the references from Commission Orders or Decisions.