STAFF INTERROGATORY #5

INTERROGATORY

Issue 2 – Cost Consequences

Topic: Introduction

Ref: Exhibit B / Tab 1 / Schedule 1 / p. 3, # 10

Preamble:
Enbridge Gas used its Abatement Construct to evaluate multi-year abatement programs.

In Enbridge Gas' 2017 Compliance Plan[1], the forecasts for its 2017 administrative costs was $2,917,100 where consulting is $561,000 and staffing is $1,120,000.

In Enbridge Gas' 2018 Compliance Plan[2], the forecasts for its 2018 administrative costs is $5,251,000 where consulting is $400,000 and staffing is $1,500,000.

In Enbridge Gas' 2018 Compliance Plan[3], it outlines its 2016 Greenhouse Gas Emissions Impact Deferral Account (GGEIDA) balance of $840,336.

Questions:

a) For 2016, please explain whether any of the administrative costs ($840,336) were used to develop its RNG Enabling Program – Upgrading Service?
   i) If yes, please outline the actual costs (including the cost elements) and actual FTEs that were used to develop its Upgrading Service? Please explain.

b) For 2017, please explain in detail whether any of the administrative costs ($2,917,100) were used to develop its RNG Enabling Program – Upgrading Service?
   i) If yes, please outline the actual costs by cost elements and actual FTEs that were used to develop its Upgrading Service?

c) For 2018, please explain in detail whether any of the administrative costs ($5,251,000) were or are intended to be used to develop its RNG Enabling Program – Upgrading Service?

[1] EB-2017-0224, Exhibit I. 1.EGDI.STAFF. 12, p 4
[2] EB-2017-0224, Exhibit D / Tab 1 / Schedule 1 / p. 2-3
[3] EB-2017-0224, Exhibit D / Tab 1 Schedule 1 / p. 2, Table 1

i) If yes, please outline the estimated costs (including the cost elements) and estimated FTEs that were used to develop its Upgrading Service? Please explain.

d) For 2016, please explain whether any of the administrative costs ($840,336) were used to develop its RNG Enabling Program – Injection Service?
   i) If yes, please outline the actual costs (including the cost elements) and actual FTEs that were used to develop its Injection Service? Please explain.

e) For 2017, please explain in detail whether any of the administrative costs ($2,917,100) were used to develop its RNG Enabling Program – Injection Service?
   i) If yes, please outline the actual costs by cost elements and actual FTEs that were used to develop its Injection Service?

f) For 2018, please explain in detail whether any of the administrative costs ($5,251,000) were or are intended to be used to develop its RNG Enabling Program – Injection Service?
   i) If yes, please outline the estimated costs (including the cost elements) and estimated FTEs that were used to develop its Injection Service? Please explain.

g) For 2016, please explain whether any of the administrative costs ($840,336) were used to develop its Geothermal Energy Service (GES) Program?
   i) If yes, please outline the actual costs (including the cost elements) and actual FTEs that were used to develop its GES Program? Please explain.

h) For 2017, please explain in detail whether any of the administrative costs ($2,917,100) were used to develop its GES Program?
   i) If yes, please outline the actual costs (including the cost elements) and actual FTEs in each year that were used to develop its GES Program? Please explain.

i) For 2018, please explain in detail whether any of the administrative costs ($5,251,000) were or are intended to be used to develop its GES Program?
   i) If yes, please outline the estimated costs (including the cost elements) and estimated FTEs that were used to develop its RNG Enabling Program? Please explain.

RESPONSE

a) to i) As outlined in the Company's EB-2017-0224 evidence at Exhibit C, Tab 5, Schedule 1, paragraph 22 the Company proposes that the cost associated with

projects in the first three stages of the Initiative Funnel be included as an administrative cost in the GGEIDA. For initiatives that have progressed out of Stage 3 and into the Implementation phase, costs would be identified and incorporated into that approved abatement activity.

Since the Low Carbon Initiative Fund and abatement resourcing requirement model outlined in the Company's EB-2017-0224 evidence have not yet been approved by the OEB the costs of developing the RNG Enabling Program – Upgrading Service, RNG Enabling Program – Injection Service, and Geothermal Energy Service were all absorbed within the Company's Customer IRM budget in 2016 and 2017. With respect to 2018 the RNG Enabling Program – Upgrading Service and Injection Service and the Geothermal Energy Service are both at the implementation phase and as such their 2018 costs will be absorbed within the programs themselves.

STAFF INTERROGATORY #6

INTERROGATORY

Issue 2 – Cost Consequences

Topic: RNG Enabling Program

Ref: Exhibit B / Tab 1 / Schedule 1 / p. 15, #44, p. 16, #48, p. 17 # 49, #50 and p.19 #56 and 57

Preamble:
Enbridge Gas states that it can play an important role as facilitator that can assist RNG producers and proposes to offer two services to RNG producers –Upgrading Service and Injection Service. The Upgrading Service is an optional service while the Injection Service is a mandatory service.

In Enbridge Gas' 2018 Compliance Plan (EB-2017-0224, Exhibit C / Tab 5 / Schedule 2 / pp. 8-9, #24 and #25) it also states that it will utilize a tendering process for RNG supplies. Further, it is considering to enter into RNG procurement contracts with terms of up to 10 years in duration.

Enbridge Gas indicates that the appropriate service charge would be included in the contract with the RNG producer. It also outlines its hypothetical example for a single RNG production facility to illustrate how the service charges are to be determined since the service fees will be site specific. For example, under the Injection Service, it will build a pipeline to attach a producer to its distribution system, odourize the bio-methane, measure the gas volumes and energy content of the gas, manage pressures and ensure that the gas meets required specifications.

Questions:

a) What is status of the provincial funding that is required for Enbridge Gas' procurement of RNG supplies? If Enbridge Gas does not received its required RNG funding from the provincial government, please explain how this will impact its RNG Enabling Program?

b) Will Enbridge Gas' long-term RNG procurement contracts with RNG suppliers include clauses related to the two services being offered under its RNG Enabling Program? Please explain.
   i) If so, please provide copies of the contract and/or provide examples of the clauses that will be included in these contracts.

c) If an RNG supplier choses not to procure the Upgrading Service, please explain how Enbridge Gas will ensure that the RNG is of the required quality (i.e., impurities have been removed) ?
   i) What are Enbridge Gas' estimated resources and costs for years 2018, 2019 and years 3-21 associated with ensuring that the RNG is of the required quality? Please explain.
   ii) How will these costs be recovered? Please explain.

d) Please provide the service agreements that Enbridge Gas will use for its RNG Enabling Program – Upgrading Service.
   i) What is expected length of the contract?

e) Please provide the service agreements that Enbridge Gas intends to use for its RNG Enabling Program – Injection Service.
   i) What is expected length of the contract?

f) Under its Injection Service, Enbridge Gas is proposing to build a pipeline to attach a producer to its distribution system. Please explain the range of the length of the pipeline that Enbridge Gas is proposing to build.
   i) Please explain what is exactly included under its Injection Service.

RESPONSE

a) On April 25th 2018 the Company was advised by the Minister of Energy that the provincial funding in support of the Company's RNG procurement proposal had been put on hold pending the provincial government election this June. Following the receipt of this notice the Company advised the respondents to its RNG procurement RFP that the RFP process will be put on hold pending confirmation of provincial government funding. In the event that the anticipated funding is not forthcoming the Company will seek out other support and if required revise its RNG procurement proposal that was presented to the Board as part its 2018 Cap and Trade Compliance Plan (EB-2017-0224).

   The RNG enabling program is not dependant on the provincial funding. As shown in Exhibit B, Tab 1, Schedule 1, pages 20 to 21, RNG producers have 4 market options. Options a) through c) are not dependant on the Company purchasing the RNG and currently there are a number of customers that have expressed interest in those options, including the City of Toronto.

b) No. The RNG Enabling services are separate and distinct from any RNG procurement activities the Company may engage in. The RNG Enabling services and RNG procurement activities will be contracted for under separate agreements.
   i) Please see response to b) above.

c) If an RNG producer chooses not to procure the RNG upgrading service from the Company Enbridge will ensure that the RNG entering the gas distribution system is of the required quality standard through the operation of its RNG injection service. Please see Exhibit B, Tab 1, Schedule 1, page 15, Figure 1. The injection system will include the facilities required to ensure that the RNG entering the distribution system conforms to the required gas quality specifications. Further, the contracts for the injection service will include gas quality specifications. Please see response to e) below for further details.
   i) These costs are not known at this time as the number, size and in service dates for RNG upgrading and injection facilities are not known at this time.
   ii) The costs associated with confirming that RNG to be injected into the Company's gas distribution meets quality standards will be recovered from the RNG producer through fees charges under Rate 401.

d) Please see Attachment 1 to this response for a pro forma copy of the Company's Biogas Services agreement, which includes the Upgrading Services Schedule.
   i) The length of these contracts will vary on a case-by-case basis but are expected range between ten and twenty years in duration.

e) Please see Attachment 1 to this response for a pro forma copy of the Company's Biogas Services agreement, which includes the Injection Services Schedule.
   i) The length of these contracts will vary on a case-by-case basis but are expected range between ten and twenty years in duration.

f) The range and length of the pipeline to facilitate RNG injection services will vary on a case-by-case basis depending on distance from the RNG production facility to the appropriate injection point on the Company's existing gas distribution network.
   i) The Company's proposed RNG injection service would include the following; supplying, installing, and operating the injection facilities, including but not limited to planning, designing, procuring, installing, constructing and engineering, commissioning, operating and maintaining equipment (measurement, regulation, compression, odorization, testing and pipeline connection) of suitable capacity and design as is required for Enbridge to provide the injection services.

BIOGAS SERVICES AGREEMENT

THIS BIOGAS SERVICES AGREEMENT ("**Agreement**") is made as of ● ***[INSTRUCTION: Insert effective date of this Agreement]*** (the "**Effective Date**") between **Enbridge Gas Distribution Inc.** ("**Company**"), a corporation existing under the laws of Ontario, whose principal place of business is located at 500 Consumers Road, Toronto, ON M2J 1P8 and ● ***[INSTRUCTION: Insert full legal name of Customer]*** ("**Customer**"), a corporation incorporated under the laws of ● ***[INSTRUCTION: Insert jurisdiction of incorporation of Customer]*** whose principal place of business is located at ● ***[INSTRUCTION: Insert Customer business address]***.

BACKGROUND:

A. Customer ***[INSTRUCTION***: ***Describe ownership and operation rights – e.g. " owns and operates")] [INSTRUCTION: Specify whether one or more potential facilities – e.g. "****a facility (the* ***"Facility")" or "***one or more facilities (each, a "**Facility**")"] at one or more locations (each, a "**Site**") that, among other attributes, produces a supply of untreated biogas generated from biomass (including biogas collected from landfill and biogas generated from anaerobic digestion) (the "**Untreated Biogas**").

B. In connection with [***INSTRUCTION: specify whether one or more Facilities – e.g. "one or more of the Facilities", or "the Facility"***], Customer desires to obtain and Company desires to provide certain biogas-related services as may be described in a schedule to this Agreement, which may include any one or more of: (a) untreated biogas upgrading and conditioning services, to produce treated biogas; and (b) renewable gas compression and injection services.

NOW THEREFORE, in consideration of the premises and the covenants and agreements herein contained, Company and Customer hereby agree as follows:

ARTICLE 1 - INTERPRETATION

1.01 Definitions

The words and phrases defined in this Agreement will have the meanings ascribed to them herein, and, unless the context otherwise specifies or requires, for the purposes of this Agreement, including its Schedules and Appendices, capitalized terms shall have the meanings set out in Appendix A.

1.02 Construction

The division of this Agreement into Articles and Sections and the insertion of headings are for convenience of reference only and do not affect the construction or interpretation of this Agreement. The terms "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles, Sections and Schedules are to Articles of, Sections of and Schedules to this Agreement. In this Agreement, words importing the singular number only include the plural and vice versa, words importing any gender include all genders and words importing persons will include individuals, partnerships,

associations, trusts, unincorporated organisations and corporations. The term "including" means "including without limiting the generality of the foregoing". A definition applies to other forms of the word. Except where otherwise expressly provided, all references to currency herein are to the lawful money of Canada. A reference to a statute, whether or not that statute has been defined, includes every amendment to it, every regulation made under it, and any enactment passed in substitution therefor or in replacement thereof. Except as otherwise specifically defined or provided for in this Agreement, words or abbreviations which have well known or trade meanings are used in accordance with their recognized meanings consistent with good utility practice. The terms "provision" and "provisions" in this Agreement refer to terms, conditions, provisions, covenants, obligations, undertakings, warranties and representations in this Agreement.

1.03 Order of Priority

In the event of any conflict or inconsistency between any of the provisions of the main terms and conditions of this Agreement and the Schedules, the inconsistency will be resolved by reference to the following descending order of priority:

(a) the main terms and conditions of this Agreement (but otherwise excluding the exhibits, appendices and Change Orders);

(b) Appendices A, B and F to this Agreement;

(c) Change Orders to effect Changes in Services;

(d) the applicable Injection Services Schedule(s) and Upgrading Services Schedule(s);

(e) the appendices to the Schedules; and

(f) Appendices C, D and E to this Agreement.

1.04 Schedules and Appendices

The following are the Schedules and Appendices to this Agreement as of the Effective Date:

Appendix A		Definitions
Appendix B	–	Designated Areas
Appendix C	–	Form of Feasibility Services Schedule
Appendix D	–	Form of Injection Services Schedule
Appendix E	–	Form of Upgrading Services Schedule
Appendix F	–	Financial Assurances

1.05 Endorsement Process

Wherever the provisions of this Agreement require or provide for an Endorsement by a Party of or to any action, persons, document, list, plan or other matter contemplated by this Agreement, this Agreement shall (unless the text expressly states that such Endorsement may be

unreasonably or arbitrarily withheld or shall be subject to the sole and/or absolute discretion of the Party providing the Endorsement) be deemed to provide that:

(a) such Endorsement shall not be unreasonably or arbitrarily withheld or delayed;

(b) the Party requesting the Endorsement shall make the request for Endorsement in writing (including by electronic communication), accompanied by such documentation or information in sufficient detail as may be reasonably required for the Party requested to provide the Endorsement to provide the Endorsement;

(c) the Party providing the Endorsement shall, within thirty (30) calendar days (or such shorter period provided in a Schedule) after the giving of a notice requesting Endorsement, advise the other Party by notice either that it Endorses or that it withholds its endorsement and in which case it shall set forth, in reasonably detail, its reasons for withholding its endorsement (which reasons may include the insufficiency, determined acting reasonably, of the information or documentation provided); and

(d) if the responding notice referred to in Subsection 1.05(c) above indicates that the request is not Endorsed, the party requesting Endorsement may elect to satisfy the objections of the approving Party and resubmit such request for Endorsement from time to time and the provision of this Section shall again apply until such time as the Endorsement is obtained.

ARTICLE 2 - PROVISION OF SERVICES

2.01 Services

During the Term (as hereinafter defined) of this Agreement, Company will provide Customer and Customer will receive from Company, in accordance with the provisions of this Agreement and of each applicable Schedule, the following services (collectively, the "**Services**"):

(1) the preparatory work and feasibility services described in Feasibility Services Schedule(s) entered into between the Parties, substantially in the form attached at Appendix C (the "**Feasibility Services**");

(2) the compression and injection services described in Injection Services Schedule(s) entered into between the Parties, substantially in the form attached at Appendix D (the "**Injection Services**"); and

(3) the Untreated Biogas upgrading and conditioning services described in Upgrading Services Schedule(s) entered into between the Parties, substantially in the form attached at Appendix E (the "**Upgrading Services**").

For certainty, the Parties shall enter into an Injection Services Schedule and, if agreed between the Parties, an Upgrading Services Schedule, for each Site.

Upon execution of a Schedule, the Schedule is incorporated by reference into this Agreement as if fully stated herein.

2.02 Performance Requirements

Company will use commercially reasonable efforts to provide the Services in accordance with all applicable Performance Requirements, but any failure to do so is not a breach or default of this Agreement and, save as provided in a Schedule to this Agreement, will not result in any refund or payment of any damages or other amounts by Company. Company will monitor and track its compliance with the Performance Requirements as provided in the applicable Upgrading Services Schedule(s).

2.03 Equipment

The title to all Equipment (including service pipes, meters, regulators, attachments and equipment) placed by Company on Customer's premises and not sold to Customer shall remain with Company, with right of removal, and no charge shall be made by Customer for use of premises occupied thereby. Customer agrees to be responsible for any loss or damage thereto resulting from wilful or negligent acts of Customer or Customer's agents or employees or any Person acting under the authority of or with the permission of Customer.

2.04 Metering

Save as otherwise provided in a Schedule, all Untreated Biogas delivered to the Upgrading Equipment and thereafter all Renewable Gas shall be measured utilizing equipment which conforms to the regulations prescribed in "Departmental Instructions for Inspection of Gas Meters and Auxiliary Devices" dated October 1976, issued by the Department of Customer & Corporate Affairs, Government of Canada, as amended from time to time. The measurement unit shall be one cubic meter of gas at a pressure of 101.325 kilopascals ("kPa") absolute and at a temperature of fifteen (15) degrees Celsius; "10^3m^3" means one thousand cubic metres. The average absolute atmospheric (barometric) pressure shall be calculated in accordance with the *Electricity and Gas Inspection Act* and the regulations made thereunder or any other legislation which may succeed the said Act, regardless of variations in actual barometric pressure from time to time. Units set out in SI (metric) are the governing units for the purposes of this Agreement. Units set out in Imperial measurement in parentheses beside their SI (metric) equivalent are for reference only and in the event of a conflict between SI (metric) and Imperial measurement herein, SI (metric) shall prevail.

2.05 Title

Save as otherwise provided in a Schedule to this Agreement, title to Biogas delivered to Company by Customer pursuant to this Agreement shall remain with Customer at all times, regardless of control or possession. For certainty, any purchase of the Biogas by Company from Customer will be the subject of a separate agreement between the Parties.

2.06 Environmental Attributes

Save as otherwise provided in another agreement between the Parties (including any Renewable Gas purchase agreement):

(a) Company acknowledges and agrees that Customer owns and shall be entitled to retain and register for use, trade and sale any and all credits, offset credits and/or other rights resulting from the displacement of traditional natural gas with Renewable Gas produced through the Services, including any reduction or displacement in emissions of greenhouse gases and other pollutants (together with all of the proceeds or benefits therefrom) (collectively, "**Environmental Attributes**").

(b) If through operation of law or any other circumstance title to any Environmental Attributes vests in Company, Company shall automatically transfer or otherwise convey such Environmental Attributes to Customer and Customer shall reimburse Company for all reasonable costs, if any, incurred by Company in connection with transferring such Environmental Attributes to Customer.

ARTICLE 3 - INTELLECTUAL PROPERTY

3.01 Ownership of Intellectual Property

Customer acknowledges and agrees that Company or licensors of the Company Intellectual Property, as the case may be, will retain and own all right, title and interest, including, without limitation, all Intellectual Property rights, in and to the Company Intellectual Property. Nothing in this Agreement transfers, conveys or confers to Customer any ownership right, title or interest in or to the Company Intellectual Property. Customer acknowledges and agrees that it will not, either during or after the Term, contest or challenge the ownership of the Company Intellectual Property by Company or licensors of Company.

3.02 Ownership of Improvements

During the Term, Customer and its employees, agents and representatives may give Company notifications of problems, solutions to identified problems, or suggested improvements or other changes with respect to the Services or the Company Intellectual Property (collectively, the "**Improvements**"). The Improvements will be the property of Company, regardless of whether Customer and its employees, agents and representatives acted alone or jointly with Company in developing the Improvements. Customer hereby assigns, at no cost, all rights, title, and interests, including without limitation all Intellectual Property rights therein, in and to the Improvements to Company effective as of the date of the Improvements' creation, and Company may use such Improvements for any purposes without notice or obligation to account to Customer. Customer will not include in any Improvements any trade-secrets, confidential information, or other proprietary information of any third party.

ARTICLE 4 - FEES AND PAYMENT

4.01 Service Fees

In consideration of the provision of the Services, Customer will pay the Service Fees to Company, without any set-off or deductions of any kind. The Service Fees shall be billed to Customer Account, over and above any other fees payable pursuant to the Customer Agreements.

4.02 Invoicing and Payment

Terms applicable to issuing of invoices and the payment thereof, including any late payment charges and any similar terms, in respect of the Services, if any, supplied under this Agreement are as set out in Section D – Bills and Section F – Payment Conditions of Part III of the Rate Handbook. Part III of the Rate Handbook shall be construed using the definitions contained in this Agreement and the terms used in the Rate Handbook and not defined in this Agreement shall be construed using the definitions in Part I of the Rate Handbook. For certainty, for purposes of this Agreement, the term "Applicant" as referenced in the Rate Handbook shall mean the "Customer" or the "Customer" in this Agreement. [***Note to Customer: In the event that the application is successful before the OEB, this clause will be amended to refer to the parts of the Rate Handbook that are applicable to the Services. This Agreement will also incorporate clauses referring to the application of the specific rate(s) associated with the Services.***]

4.03 Taxes

All fees and payments stated herein are exclusive of all taxes and duties now in force or enacted in the future that may be imposed in connection with this Agreement. Customer will pay all such taxes and duties, including sales, use, excise, personal property, value-added, goods and services, and any other federal, provincial, state or local taxes, withholdings, tariffs, import duties or import license, charges, or like charges and any interest or penalties thereon imposed by a Governmental Authority, but exclusive of taxes based on Company's net income. Customer will make all payments free and clear of, and without reduction for, any withholding taxes; any such taxes imposed on payments by Customer hereunder will be Customer's sole responsibility. Customer will provide Company with official receipts or such other evidence as Company may reasonably request, to establish that such taxes have been paid. Any payments payable under this Agreement to Company that are otherwise subject to the deeming rule in Section 182 of the *Excise Tax Act* (Canada) shall be increased by an amount equal to the amount determined by multiplying any such payments by the applicable rate of GST/HST.

4.04 Remedies in the Event of Failure to Pay

In addition to any other remedies provided in this Agreement and the Schedules, at any time Company shall have the right to set-off an amount due, owing and unpaid by Customer to Company against any amount owing to Customer by Company, upon delivering a notice to Customer to that effect.

4.05 Retention of Records

All charts and calculations upon which an Company invoice is based, and Company's books and records insofar as they pertain to measurement and settlement for accounts hereunder, shall be retained by Company for the longer of (A) three (3) years from the date of such invoice, and (B) the period while any claim which relates to such invoice, and of which Company receives written notice from Customer within such three-year period, is outstanding; and shall be available for inspection by Customer on reasonable prior notice during normal office hours of Company.

ARTICLE 5 - REGULATORY REQUIREMENTS

5.01 *Ontario Energy Board Act* and Regulations

Notwithstanding anything to the contrary herein, the Parties acknowledge that this Agreement may be subject to any rule applicable to Company made by the Ontario Energy Board pursuant to the *Ontario Energy Board Act*, S.O. 1998, Sched. B., s. 44 (the "**OEB Act**") including the *Affiliate Relationships Code for Gas Utilities* dated July 31, 1999, revised December 31, 2004 with effect June 9, 2005 (the "***Code***") as amended from time to time. All amendments to the OEB Act or the Code and all rules applicable to Company made pursuant to the OEB Act, which require changes to the terms of this Agreement, which affect the Services or the Service Fees after the date hereof shall be treated as a Change in Law and Customer agrees to do all such things as are necessary to assist Company to comply with the OEB Act and the Code.

5.02 Company's Authorizations and Approvals

During the term of this Agreement, Customer agrees to support and cooperate with, and to not oppose, obstruct or otherwise interfere with in any manner, the efforts of Company to obtain all authorizations and/or exemptions and supplements and amendments thereto necessary for Company to construct, own, operate, and maintain, under Company's proposed regulatory framework, the Equipment and to provide the Services.

5.03 Change in Law

(1) Upon the occurrence of a Change in Law, any Party materially affected by the Change in Law may notify the other Party of such occurrence. The notice shall identify the terms of the Agreement affected by the Change in Law ("**Affected Terms**") and describe in reasonable detail the Change in Law and the terms upon which the affected party proposes to address the Affected Terms.

(2) Upon notice of a Change in Law, the obligations of both Parties under this Agreement with respect to the Affected Terms shall be suspended and the Parties shall renegotiate the Affected Terms in good faith in order to appropriately pass through or otherwise address or reflect the effects of the Change in Law.

(3) If the Parties are unable to agree on revised material terms or conditions within thirty (30) days following the notice of a Change in Law, the Party affected by the Change in Law may terminate the Agreement and, notwithstanding anything to

the contrary in this Agreement, the applicable Termination Charge specified in a Schedule shall apply.

5.04 No Waiver of Company Rights as Distributor

Nothing in this Agreement shall be construed in a manner that prohibits, restricts or in any manner limits, Company's rights and obligations as a rate-regulated distributor of natural gas (a "**Distributor**") in accordance with requirements of the *Ontario Energy Board Act, 1998* (Ontario), the *Public Utilities Act* (Ontario) and any other Applicable Laws that pertain to Company as a Distributor.

5.05 Consent to Affiliate Disclosure

Customer acknowledges that Company may require the support and approval of certain of its Affiliates in order to assess and proceed with this Agreement, and agrees that Company may disclose any information Company has about Customer to Company's Affiliates to support the activities contemplated by this Agreement. This constitutes written consent as required by the OEB's *Gas Distribution Access Rule* and *Affiliate Relationships Code for Gas Utilities*.

5.06 Government Regulations

(1) This Agreement is subject to (A) the maintenance of all Required Orders, and (B) all Applicable Laws. Each of the Parties shall comply with the terms of all Required Orders applicable to it and shall maintain the same in full force and effect throughout the Term.

(2) With respect to Required Orders applicable to each of the Sites, each of the Parties have the following responsibilities:

(a) subject to Section 5.06(2)(b), Customer shall obtain all Required Orders that are required in connection with the installation and operation of the Equipment including, but not limited to zoning and by-law approvals, building permits and underground locates, and all approvals that may be required from provincial or federal government departments or regulatory authorities with jurisdiction over the subject matter of this Agreement, other than as expressly provided in this Agreement, and such other Required Orders as relate to the ownership and operation of the Facility and the Site (the "**Customer Acquired Permits**");

(b) Company shall be responsible for compliance with all Required Orders specifically applicable to the Services as described in a Schedule ("**Company Acquired Permits**"); and

(c) save as otherwise provided in a Schedule, Customer shall be responsible, at its own cost and expense without any dollar contribution or reimbursement from Company, for any modification(s) to the Site required by any Required Order.

ARTICLE 6 - CONDITIONS PRECEDENT

6.01 Conditions Precedent

The obligations of each of Company and Customer under each Schedule are subject to the conditions precedent set out in the Schedule.

6.02 Operation of Conditions Precedent

(1) Company and Customer shall each use due diligence and reasonable efforts to satisfy and fulfill the conditions precedent. Company shall notify Customer forthwith in writing of the satisfaction, or in the case of Company conditions precedent that may be waived in whole or in part by Company, the waiver, of each of its conditions precedent.

(2) If Company concludes that it will not be able to satisfy a condition precedent, Company may, upon written notice to Customer, terminate the relevant Schedule and any related Customer Agreements and upon the giving of such notice, the relevant Schedule and such related Customer Agreements shall be of no further force and effect and each of the Parties shall be released from all further obligations thereunder. Such termination shall be without prejudice to any rights or remedies that a Party may have for breaches of the relevant Schedule and this Agreement prior to such termination and any liability a Party may have incurred before such termination or as a result of such termination shall not thereby be released.

ARTICLE 7 - OBLIGATIONS OF CUSTOMER

7.01 Customer Responsibilities

Customer will:

(1) separate from this Agreement, enter into the applicable Customer Agreements with Company;

(2) provide Company with technical assistance concerning each applicable Site as Company may require, including but not limited to Site drawings;

(3) deliver, commission and operate each Facility in accordance with this Agreement (including the specifications agreed to by the Parties in the relevant Schedule(s) pertaining to the Site), to ensure Customer's obligations under this Agreement are met and to ensure the provision of the Services by Company in accordance with this Agreement;

(4) provide Company with notice of any changes to each applicable Site and Facility that may impact the operation of the Equipment or performance of the Services (including changes in locations of utilities and other equipment on each Site, traffic flow patterns).

(5) provide such access to Customer's Site and Facilities as may be required by Company, for the purposes of performing the Services, as further set out in Appendix B to this Agreement and as may be more specifically defined in a Schedule to this Agreement;

(6) ensure that its personnel (including those of approved sub-contractors), when entering the Designated Areas shall comply with all security policies, regulations or directives relating to the Designated Areas; and

(7) provide such Customer materials or information, at no additional cost, as Company requires to carry out the Services in a timely manner and ensure that such Customer materials or information are complete and accurate.

7.02 Customer's Acts or Omissions

If Company's performance of its obligations under this Agreement is prevented or delayed by any act or omission of Customer or Customer Representatives, Company will not be deemed in breach of its obligations under this Agreement or otherwise liable for any costs, charges or losses sustained or incurred by Customer, in each case, to the extent arising directly or indirectly from such prevention or delay.

ARTICLE 8 - GOVERNANCE

8.01 Cooperation

Each Party will

(1) cooperate with, and cause all of its respective subcontractors to cooperate with, the other Party in all matters relating to the Services and the operation of their respective assets at each Site; and

(2) respond promptly to any request by the other Party to provide direction, information, approvals, authorizations or decisions, at no additional cost, that are necessary for the other Party to perform their respective obligations under this Agreement.

8.02 Relationship Managers

(1) To facilitate the proper management of the relationship of the Parties in connection with this Agreement, Customer and Company will each designate and make available an employee of the Party whose duties will be to act as primary liaison between Customer and Company for all matters relating to this Agreement (each, a "**Relationship Manager**"). If a designated Relationship Manager is not available due to illness, vacation or other reason, a secondary Relationship Manager will act as the Relationship Manager on a temporary secondary basis. As of the Effective Date of this Agreement, the Relationship Manager (and secondary Relationship Manager) for Customer is as follows:

(a) Customer Relationship Manager: [●]

(b) Customer Secondary Relationship Manager: [●]

(2) The Relationship Managers shall meet no less frequently than on a quarterly basis to manage the relationship between the Parties. Customer and Company agree to be solely responsible for any costs and expenses that may be incurred by them respectively in connection with the Relationship Manager meetings.

8.03 Site Managers

For each Site at which the Services are provided, each Party shall designate and make available an employee who will act as the Parfsty's respective relationship/project manager at the Site and be responsible for the operation of the Parties' respective assets at the site, and shall be the first point of contact in the event of an emergency at the site (each, a "**Site Manager**"). Customer Site Manager or designee shall be available during all business hours and shall provide or facilitate all access, scheduling and operating and maintenance at Customer's location to support Company as necessary to facilitate the project and the performance of Services.

8.04 Change to Representatives

The actions taken by each Party's Relationship Manager and Site Manager(s) shall be deemed the acts of the Party. Either Party may at any time, upon written notice to the other Party, change their respective Relationship Manager and Site Manager.

ARTICLE 9 - CONFIDENTIAL INFORMATION

9.01 Confidential Information

(1) Each Party acknowledges that Confidential Information will be exchanged between the Parties pursuant to this Agreement. Each Party will use no less than the same means it uses to protect its own similar confidential and proprietary information, but in any event not less than reasonable means, to prevent the disclosure and to protect the confidentiality of the Confidential Information of the other Party. Each Party agrees that: (a) as between the Parties, such Confidential Information is and shall remain the property of the Disclosing Party; and (b) it will not disclose or use the Confidential Information of the other Party except for the purposes of this Agreement and as authorized under this Agreement.

(2) Notwithstanding any other provision of this Agreement, the Recipient of Confidential Information may use or disclose the Confidential Information to the extent that such Confidential Information is: (a) already known by the Recipient without an obligation of confidentiality; (b) publicly known or becomes publicly known through no unauthorised act of the Recipient; (c) rightfully received from a third party without any obligation of confidentiality; (d) independently developed

by the Recipient without use of the Confidential Information of the Disclosing Party; or (e) approved by the Disclosing Party for disclosure.

(3) The Recipient may disclose Confidential Information of the Disclosing Party if the disclosure is required as a matter of law or by order of a court, Governmental Authority, or arbitral tribunal of competent jurisdiction or it is needed in connection with the prosecution or defence of a claim, provided: (a) the Recipient gives the Disclosing Party reasonable prior notice of such disclosure (to the extent legally permitted); and (b) that Recipient takes reasonable and lawful actions requested by the Disclosing Party and cooperates with the Disclosing Party to avoid and minimize the extent of such disclosure.

(4) The Recipient will, and will cause all of its representatives to, safeguard and maintain the Confidential Information of the Disclosing Party in strict confidence and will not, and will cause all such representatives to not, disclose, provide, or make such Confidential Information or any part thereof available in any form or medium to any person, except to such of its representatives and to other third parties who have a need to access such Confidential Information in order to enable the Recipient to exercise its rights under this Agreement and are bound by and so long as such representatives and third parties are bound by confidentiality obligations at least as stringent as the provisions set out herein.

9.02 Disclosure by Company

The Parties acknowledge and agree that where Company is the Recipient, it shall have the right to retain and disclose certain Confidential Information, as it may determine acting reasonably (the "**Retained Confidential Information**") is required for use by Company in connection with any regulatory or other governmental proceeding to which it is, or may in the future become, a party, including without limitation submissions to regulatory authorities such as the Ontario Energy Board (collectively referred to herein as the "**Regulatory Proceedings**"), and, in such event, the Parties agree that Company shall not be restricted from disclosure of the Retained Confidential Information where Company determines, in its sole discretion acting reasonably, it is necessary or appropriate to do so in connection with any Regulatory Proceedings. Customer hereby acknowledges that any such Retained Confidential Information disclosed in Regulatory Proceedings by Company pursuant to this Section may, as a result of such disclosure, become part of the public record.

9.03 Right to Perform Company Services For Others

Customer recognizes that Company is in the business of providing gas distribution and related services and may perform services similar to the Company Services for third party customers. Subject to Company's confidentiality obligations, Company retains the right to use, and nothing will prevent Company from using, any ideas, concepts, methods, processes, know-how, organization, or techniques including, without limitation, any such materials produced by Company to provide the Services, in providing any services to any third parties.

ARTICLE 10 - CHANGE IN SERVICES

10.01 Change Events.

(1) Minor Variations in Services. Company shall have the right, at any time, to make minor variations in the Services that do not involve an adjustment in the Service Fees and are compatible with the design concept of the Equipment.

(2) Customer Requested Change in Services. In addition to the provisions of subsection (3), Customer may request a Change in Services in writing to Company, subject to Company's sole discretion. In such event, Company shall prepare and submit to Customer a written estimate relating to the proposed Change in Services, including: (a) any projected change in the cost of the performance of the Services and any projected modification of the Service Fees occasioned by such Change in Services and (b) the effect such Change in Services could be expected to have on the performance of the Equipment.

(3) Change in Services. If, during the Term, Company encounters the following events, a Change in Services to reflect the extent to which certain events or circumstances (as more fully described in a Schedule) increase Company's cost of or time required for performance of the Services, affect the performance of the Equipment or result in a change to the Equipment will be implemented:

(a) changes in the quality or quantity of Untreated Biogas supplied by Customer from the Untreated Biogas Specifications; or

(b) as a result of damage to the Equipment due to Customer's negligence or wilfull misconduct after the Commissioning Date; or

(c) a suspension or change in the Services as a result of a change in Applicable Law or requirements of a Governmental Authority, or a Latent Site Defect.

10.02 Change in Services could be expected to have on the performance of the Equipment

If Customer elects to proceed with a more detailed examination of such proposed Change in Services, within such period as shall be agreed upon by the Parties, Company shall submit to Customer a detailed estimate relating to the contemplated change and Customer shall be responsible for the cost of preparing the detailed estimate. If Customer elects to proceed with the proposed Change in Services, Customer and Company shall agree upon a change order that shall include: (i) an adjustment in the Service Fees for the costs expected to be incurred by Company as a result of such Change in Services less any savings or costs not incurred as a result of such Change in Services, and (ii) an adjustment in other terms of this Agreement, including but not limited to the Performance Requirements as a result of such Change in Services.

ARTICLE 11 - REPRESENTATIONS AND WARRANTIES

11.01 Representations and Warranties of Customer

In addition to any other representations and warranties given to Company under this Agreement (including any Schedules), Customer represents and warrants to Company that at the date hereof and at all times during the Term:

(a) all necessary action has been taken by Customer to authorize the execution, delivery and performance by Customer of this Agreement and this Agreement constitutes a legal, valid and binding obligation enforceable against Customer in accordance with its terms;

(b) save as may be specifically provided in a Schedule to this Agreement, Customer shall have good and marketable title in and to the Biogas to be delivered to Company and shall be entitled to deliver such Biogas to Company in accordance with the terms of this Agreement, for Company to deliver the Services, free and clear of any adverse claim of any nature of kind whatsoever; and

(c) Biogas delivered to Company by or for Customer will not be subject to any royalties, taxes (federal and/or provincial) or other charges payable by, or that may become a liability of Company;

and acknowledges and agrees that Company is relying on the accuracy of each of such representations and warranties in connection with the entering into of this Agreement.

11.02 Representations and Warranties of Company.

In addition to any other representations and warranties given to Customer under the Agreement (including any Schedules), Company represents and warrants to Customer that at the date hereof and at all times during the Term:

(a) all necessary action has been taken by Company to authorize the execution, delivery and performance by Company of this Agreement and this Agreement constitutes a legal, valid and binding obligation enforceable against Company in accordance with its terms;

and acknowledges and agrees that Customer is relying on the accuracy of each of such representations and warranties in connection with the entering into of this Agreement.

ARTICLE 12 - DISCLAIMERS

12.01 Disclaimer

(1) EXCEPT AS EXPRESSLY PROVIDED UNDER THIS AGREEMENT (INCLUDING, FOR CERTAINTY, A SCHEDULE TO THIS AGREEMENT), THE SERVICES ARE PROVIDED “AS IS” AND COMPANY EXPRESSLY DISCLAIMS ANY AND ALL WARRANTIES, CONDITIONS, ENDORSEMENTS,

GUARANTEES, OR REPRESENTATIONS OF ANY KIND OR NATURE, EXPRESS OR IMPLIED, INCLUDING WITHOUT LIMITATION, WARRANTIES, CONDITIONS, ENDORSEMENTS, GUARANTEES, OR REPRESENTATIONS OF SATISFACTORY QUALITY, PERFORMANCE, DURABILITY, MERCHANTABILITY, MERCHANTABLE QUALITY, FITNESS FOR A PARTICULAR PURPOSE, TITLE AND THOSE ARISING BY STATUTE OR OTHERWISE IN LAW OR FROM A COURSE OF DEALING OR USE OF TRADE.

(2) FURTHER, THE SERVICES MAY BE INTERRUPTED OR UNAVAILABLE FOR THE PURPOSES OF PERFORMING MAINTENANCE OR UPGRADES. COMPANY WILL NOT BE RESPONSIBLE FOR: (I) SERVICE IMPAIRMENTS CAUSED BY ACTS WITHIN THE CONTROL OF CUSTOMER; OR (II) SERVICES PROVIDED BY OTHER SERVICE PROVIDERS.

ARTICLE 13 - FINANCIAL ASSURANCES

13.01 Requirement for Financial Assurances

Contemporaneously with the execution of this Agreement and at any time during the Term, Company may, upon notice to Customer, require Customer to provide Company, and Customer shall provide if Company so requests, financial assurances in respect of Customer's obligations hereunder in the amount and of the type required by Company (the "**Financial Assurances**"), all in accordance with the terms set out in Appendix F. Initially, the Financial Assurances required by Company to be provided by Customer shall be those set out in Appendix F.

13.02 Nature of Financial Assurances

Any request for such Financial Assurances shall be based upon the creditworthiness of Customer, and shall be consistent with Company's then current policies relating to customer account security applicable to like customers. Such Financial Assurances may consist of an irrevocable letter of credit in a form and from an issuer acceptable to Company and/or such other security as Company may specify.

13.03 Third Party Credit Review

Without in any way limiting Company's rights under this Article 13, Company may from time to time contract with or use the services of a qualified, arm's length third party to assess, review and/or provide comment on the creditworthiness of Customer. If such arm's length third party advises Company that an adjustment to the Financial Assurances is recommended, Company shall be entitled to rely on such recommendations and require Customer to adjust its Financial Assurances accordingly pursuant to the foregoing terms of this Article 13.

13.04 Realization of Financial Assurances

Company shall be entitled to realize upon any Financial Assurances in the manner and to the extent provided for and set out in this Agreement, including Appendix F, and such Financial Assurances.

ARTICLE 14 - INDEMNIFICATION

14.01 Indemnification by Company

Subject to any limitations specifically set out in this Agreement, Company shall save harmless and indemnify Customer, its directors, officers, employees and agents from and against any and all liability (including injury, loss, damage, expense or other cost) incurred by any of them, howsoever caused, resulting from, arising out of or relating to the negligence or wilful misconduct Company or any of Company's employees or agents or any Person acting under the authority of or with the permission of Company. Company further agrees to indemnify and hold Customer, its directors, officers, employees and agents harmless from and against any Canadian federal or provincial income taxes resulting from any payment made under this Section 14.01.

Upon assuming the defence of any action covered under this section Company shall keep Customer reasonably informed of the status of the matter, and Company shall make no admission of liability or fault on Customer's part without Customer's written permission.

Notwithstanding any other provision in this Agreement, Company shall not be liable to Customer for any loss or damage to persons or property resulting from Customer's entries upon, occupancy, use, or other activities in the Designated Areas or operation, alteration, maintenance, repair or other activities relating to the Equipment or from any damage caused by fire or other casualty or by any person not employed or controlled by Company, or as the result of any existing or future condition of the Facility.

14.02 Indemnification by Customer

Subject to any limitations specifically set out in this Agreement, Customer shall save harmless and indemnify Company, its directors, officers, employees and agents from and against any and all liability (including injury, loss, damage, expense or other cost) incurred by Company or of Company to any third parties, howsoever caused, resulting from, arising out of or relating to the breach of this Agreement by Customer, the negligence or wilful act, omission or misconduct of Customer or any of Customer's employees or agents or any Person acting under the authority of or with the permission of Customer. Customer further agrees to indemnify and hold Company, its directors, officers, employees and agents harmless from and against any Canadian federal or provincial income taxes resulting from any payment made under this Section 14.02.

Customer further agrees to save harmless and indemnify Company, its directors, officers, employees and agents from and against any and all liability (including injury, loss, damage, expense or other cost) incurred by any of them, howsoever caused, resulting from, arising out of or relating to environmental conditions at the Site that are not related to or arise out of the actions of Company, including without limitation, any and all liability relating to the migration of contaminants and/or pollutants from the Site.

Upon assuming the defence of any action covered under this section Customer shall keep Company reasonably informed of the status of the matter, Customer shall make no admission of liability or fault on Company's part without Company's written permission.

ARTICLE 15 - LIMITATION OF LIABILITY

15.01 Limitation of Liability

(1) IN NO EVENT WILL COMPANY'S AGGREGATE LIABILITY ARISING OUT OF OR RELATED TO THIS AGREEMENT, WHETHER ARISING OUT OF OR RELATED TO BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE) OR OTHERWISE, EXCEED THE LOSS SUSTAINED BY SUCH OTHER PARTY AS A RESULT OF DIRECT PHYSICAL DAMAGE SUSTAINED BY SUCH OTHER PARTY, INCLUDING REASONABLE COSTS OF REPAIR OR REPLACEMENT. THE FOREGOING LIMITATIONS WILL APPLY EVEN IF CUSTOMER'S REMEDIES UNDER THIS AGREEMENT FAIL OF THEIR ESSENTIAL PURPOSE.

(2) IN NO EVENT WILL COMPANY BE LIABLE UNDER THIS AGREEMENT TO CUSTOMER OR ANY THIRD PARTY FOR ANY CONSEQUENTIAL, INCIDENTAL, INDIRECT, EXEMPLARY, SPECIAL, EXEMPLARY OR PUNITIVE DAMAGES, INCLUDING ANY DAMAGES FOR BUSINESS INTERRUPTION, LOSS OF USE, DATA, REVENUE OR PROFIT OR FAILURE TO REALIZE EXPECTED PROFITS OR SAVINGS, WHETHER ARISING OUT OF BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE) OR OTHERWISE, REGARDLESS OF WHETHER SUCH DAMAGES WERE FORESEEABLE AND WHETHER OR NOT CUSTOMER WAS ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

(3) NO IMPLIED WARRANTY OF MERCHANTABLE QUALITY, OR OF FITNESS FOR PURPOSE SHALL APPLY AND ALL WARRANTIES IMPLIED BY LAW OR STATUTE ARE SPECIFICALLY DISCLAIMED BY COMPANY.

(4) Customer shall not be entitled to compensation for any inconvenience, nuisance or discomfort attributable to the execution by Company of its obligations in accordance with the terms of this Agreement.

(5) Company shall not be liable for and expressly disclaims liability for any loss, damage or injury that directly or indirectly results from or in any manner arises out of or in connection with (i) any breach by Company of any of its obligations under this Agreement that directly or indirectly results from or in any manner arises out of or in connection with any breach by Customer of any of its obligations this Agreement; (ii) any Latent Site Defect that cannot be remedied by a Change in Services.

ARTICLE 16 - TERM AND TERMINATION

16.01 Term and Renewal

(1) The term of this Agreement will commence on the Effective Date and expire on **[*]** (the "**Initial Term**"), unless terminated earlier in accordance with this Agreement (together with all renewals and extensions, the "**Term**").

(2) Each Schedule will set out its term and any provisions relating to its renewal or extension. If the term of a Schedule extends past the termination or expiry of the Term, then such Schedule including the terms and conditions of this Agreement deemed incorporated into such Schedule will survive the termination or expiry of the Term. For greater certainty, no new Schedule under this Agreement may be entered into between the Parties after the termination or expiry of the Term.

16.02 Termination

(1) *Customer Event of Default.* In addition to any other events set out in this Agreement, the occurrence of any one or more of the following events shall constitute a default by Customer under this Agreement and shall be considered an event of default (a "**Customer Event of Default**") if such default is not remedied prior to the expiry of the relevant notice period (if any) or the relevant cure period (if any) applicable to such default as hereinafter set out:

(a) if Customer fails to make any payment or payments of the Service Fees or any other sums owing under the Agreement or any Schedules, and where such default continues for thirty (30) days after written notice has been issued to Customer by Company stating the nature of the default;

(b) if Customer fails to perform any covenant or obligation that Customer was required to perform under this Agreement or any Schedules and where such default is capable of being cured using reasonable diligence and shall continue unremedied: (A) for a period of thirty (30) days after written notice has been issued to Customer by Company stating the nature of the default; or (B) such longer period as may be reasonably necessary to cure such failure, provided that Customer has demonstrated that: (i) it is proceeding with all due diligence to cure or cause to be cured such failure, (ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to Company, acting reasonably, and (iii) it shall thereafter cure such failure with all due diligence and within the time frame acceptable to Company, acting reasonably;

(c) if (A) Customer fails to perform any covenant or obligation that Customer was required to perform under this Agreement or any Schedules, and (B) such failure has or shall have, or could reasonably be expected to have, an adverse effect on Company's ability to deliver the Services, and (C) such failure shall continue unremedied following notice thereof (stating the nature of the default) from Company to Customer for: (1) a period of ten (10) days; or (2) such longer period as Company, acting reasonably, may agree; or

(d) if there occurs an event of default, breach or default of Customer under any other Customer Agreement.

(2) *Company Remedies.* In the event of a Customer Event of Default, or a Latent Site Defect that cannot be remedied by a Change of Services, then Company shall have the following non-exclusive rights and remedies:

(a) to suspend performance of all or any of the Services until Customer cures such Customer Event of Default or removes the Latent Site Defect, in which event, Customer shall be liable for all additional costs and expenses incurred by Company arising out of such suspension;

(b) subject to Article 15, recovery of all reasonable costs and expenses incurred by Company in mitigating the Customer Event of Default; and

(c) to terminate this Agreement (including all Schedules then in effect) or the Schedule (or Schedules) to which the Customer Event of Default relates, upon 10 days' notice, by delivering a written notice of termination for cause to Customer (a "**Company With Cause Termination Notice**"), specifying the date upon which the Schedule(s) will terminate.

(3) *Company Event of Default.* In addition to any other events set out in this Agreement, the occurrence of any one or more of the following events shall constitute a default by Company under this Agreement and shall be considered an event of default (an "**Company Event of Default**") if such default is not remedied prior to the expiry of the relevant notice period (if any) or the relevant cure period (if any) applicable to such default as hereinafter set out:

(a) if Company fails to perform any covenant or obligation that Company was required to perform under this Agreement or any Schedules and where such default is capable of being cured using reasonable diligence and shall continue unremedied: (A) for a period of thirty (30) days after written notice has been issued to Company by Customer stating the nature of the default; or (B) such longer period as may be reasonably necessary to cure such failure, provided that Company has demonstrated that: (i) it is proceeding with all due diligence to cure or cause to be cured such failure, (ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to Customer, acting reasonably, and (iii) it shall thereafter cure such failure with all due diligence and within the time frame acceptable to Customer, acting reasonably; or

(b) if (A) Company fails to perform any covenant or obligation that Company was required to perform under this Agreement or any Schedules, and (B) such failure has or shall have, or could reasonably be expected to have, a material adverse effect on Customer, and (C) such failure shall continue unremedied following notice thereof (stating the nature of the default) from Customer to Company for: (1) a period of ten (10) days; or (2) such longer period as Customer, acting reasonably, may agree.

(4) *Customer Remedies.* In the event of a Company Event of Default then Customer shall have the following non-exclusive rights and remedies:

(a) subject to Article 14, recovery of all reasonable costs and expenses incurred by Customer in mitigating the Company Event of Default; and

(b) to terminate the Schedule (or Schedules) to which the Company Event of Default relates, upon 10 days' notice, by delivering a written notice of termination for cause to Company, specifying the date upon which the Schedule (or Schedules) will terminate.

(5) *Termination for Cause by Either Party*. This Agreement may be terminated by either Party in the event: (a) a receiver, trustee, administrator, or administrative receiver should be appointed for the Party or its property; (b) the Party makes an assignment for the benefit of creditors; (c) any proceedings should be commenced against the Party under any bankruptcy, insolvency, or debtor's relief law, and such proceedings will not be vacated or set aside within fifteen (15) days from the date of commencement thereof; or (d) the Party should be liquidated or dissolved.

(6) *Termination without Cause by Customer*. Customer may, at its sole option, terminate this Agreement or any Schedule upon 120 days' notice, by delivering a written notice of termination to Company (a "**Without Cause Termination Notice**"), specifying the date upon which this Agreement or the relevant Schedule(s) will terminate, provided that if Customer terminates an Injection Services Schedule for a Site, any associated Upgrading Services Schedule associated with such Site shall also terminate.

16.03 <u>Effect Of Termination</u>

(1) Upon termination of this Agreement or a Schedule:

(a) Company will be entitled to immediately cease providing the Services (for certainty, in the case of the termination of a Schedule, Company may cease providing the Services under the relevant Schedule); and

(b) Customer will forthwith pay to Company all amounts owing under this Agreement (or the relevant Schedule, if a Schedule is terminated), including all Service Fees up to the effective date of termination, and the Termination Charge pursuant to subsection 16.03(2).

(2) The Termination Charge is payable if any of the following occurs: (i) Company has issued an Company With Cause Termination Notice pursuant to subsection 16.02(2)(c); (ii) the Customer has issued a Without Cause Termination Notice pursuant to subsection 16.02(6); or (iii) Company has provided notice pursuant to subsection 6.02(2).

(3) Notwithstanding the termination or expiration of this Agreement or a Schedule thereto, Customer shall permit unimpeded access to the Site by Company, so that Company can undertake any Decommissioning provided for in the relevant Schedule(s), and Customer shall pay any related Decommissioning costs.

(4) In the event all of the Schedules to this Agreement have been terminated (including pursuant to subsections 16.02(2)(c), 16.02(4)(b), 16.02(5), or 16.02(6)), this Agreement shall also terminate as of the effective date of termination of the last extant Schedule.

16.04 Survival

The termination of this Agreement will not terminate those obligations and rights of the Parties pursuant to provisions of this Agreement which by their nature and intent are to survive, and such provisions will survive the termination of this Agreement. Without limiting the foregoing, the respective rights and obligations of the Parties under Section 1.2 (Construction), Section 1.03 (Order of Priority), Section 2.06 (Environmental Attributes), Article 3 (Intellectual Property), Article 4 (Fees and Payment), Section 5.04 (No Waiver of Company Rights as Distributor), Section 5.05 (Consent to Affiliate Disclosure), Article 9 (Confidential Information), Article 11 (Representations and Warranties), Article 12 (Disclaimers), Article 14 (Indemnification), Article 15 (Limitation of Liability), Section 16.03 (Effect of Termination), Article 17 (Insurance Requirements), Article 18 (General) and this Section 16.04 will survive the termination of this Agreement regardless of when such termination becomes effective. In no event will any termination of this Agreement relieve Customer of the obligation to pay any fees payable to Company accrued under this Agreement.

ARTICLE 17 - INSURANCE REQUIREMENTS

17.01 Required Customer Insurance.

(1) At all times during the Term of the Agreement and for so long thereafter as a claim related to this Agreement is possible under applicable statutes of limitations, Customer shall maintain at its own expense, the insurance coverage outlined below, in each case with insurers having financial security ratings of at least “A-” by AM Best or “A” by Standard & Poor’s and which are authorized to do business in Ontario.

(a) **Commercial General Liability** coverage with a limit of FIVE MILLION DOLLARS ($5,000,000) each occurrence for bodily injury and property damage arising out of or relating to Customer’s activities under this Agreement or at the Sites. The policy shall include contractual liability, cross liability, severability of interests and coverage for limited time element pollution.

(b) **Commercial Auto Liability** covering all vehicles used by Customer at the Sites with a combined single limit of FIVE MILLION DOLLARS ($5,000,000) for injury or death of one or more persons or damage to or destruction of property as a result of each accident.

(2) Subject to the total required amount of insurance for each individual insurance coverage requirement herein, the amounts of insurance specified in the foregoing sections may be satisfied through a combination of primary and excess insurance limits.

(3) Customer shall ensure that each insurance carrier providing coverage hereunder provides (in each case arranged to provide the maximum benefit to Company), the following:

(a) The inclusion of "Enbridge Gas Distribution Inc." as additional insured in insurance policies under subsection 15.01(1)(a).

(b) Waiver of insurers' rights of recovery, contribution, subrogation, set-off or counterclaim, in favour of Company, in all policies of insurance under this Article 15.

(c) That coverage, in all of Customer's insurance policies (whether such policies are primary, umbrella or excess) under this Article 15 or arising out of or related to this Agreement in any way, shall be written to respond on a primary and non-contributory basis irrespective of any other applicable insurance otherwise available to Company under this Agreement.

(4) Insurance maintained by Customer shall not be cancelled without thirty (30) days prior written notice being furnished to Company.

(5) Upon execution of this Agreement, and on an annual basis thereafter until this Agreement is terminated, Customer shall provide to Company (or Company's designated representative) Certificate(s) of Insurance on standard forms regularly accepted in the industry certifying Customer's compliance with this Article 15 and specifically identifying coverage extensions and endorsements required herein.

(6) Customer shall require all its subcontractors to provide insurance coverage in accordance with this Article 15. Customer shall ensure that all insurance maintained by its subcontractors providing services to Customer at the Site include a waiver of insurers' rights of recovery, contribution, subrogation, set-off or counterclaim in favor of Company. The failure of any subcontractor to obtain and maintain the required insurance shall not in any way impact the obligations of Customer under this Agreement.

ARTICLE 18 - GENERAL

18.01 Notice

Any notice or other communication to be given under or pursuant to the provisions hereof or in any way concerning this Agreement will be sufficiently given if reduced to writing and delivered to the person to whom such communication is to be given or sent by courier, facsimile or electronic internet communication, addressed to such person at the address set forth below or at such other address as may be specified by a Party to the other Party by proper notice under this Agreement:

If to **Company**:

●
●
Attention: ●
Facsimile: ●
Email: ●

If to Customer**:**

●
●
Attention: ●
Facsimile: ●
Email: ●

or at such other address as may be specified therefor by proper notice hereunder. A notice or communication shall be deemed to have been sent and received on the day it is delivered personally or by courier or by facsimile or by electronic internet communication. If such day is not a Business Day or if the notice or communication is received after 5:00 PM (at the place of receipt) on any Business Day, the notice or communication shall be deemed to have been sent and received on the immediately following Business Day.

18.02 Force Majeure

Except for the obligation to pay amounts due and owing under this Agreement, if and to the extent that a Party's performance of any of its obligations pursuant to this Agreement is prevented, hindered or delayed by an unforeseen reason beyond its reasonable control, including, but not limited to work stoppages, strikes, labour disputes, delay in transportation, delay in delivery by vendors, suppliers or licensors not affiliated with a Party, failure of utilities or telecommunications, breakage or accident to machinery or equipment or lines of pipe used to transport gas, the necessity for making repairs to or alterations of such machinery or equipment or lines of pipe or inability to obtain materials, supplies (including a supply of services) or permits required to perform a Party's obligations under this Agreement, impairment of the Company Services by third parties, fire, civil disobedience, terrorism, riots, wars or natural disasters, but excluding financial inability, (in each case, a "**Force Majeure Event**") then, upon giving prompt notice to the other Party, the non performing, hindered or delayed Party will be excused for such non-performance, hindrance or delay, as applicable, of those obligations affected by the Force Majeure Event for as long as such Force Majeure Event continues and such Party continues to use its reasonable commercial efforts to recommence performance whenever and to whatever extent possible. Notwithstanding any other term of this Section, no Party shall be entitled to, or to claim, the benefit of these provisions pertaining to a Force Majeure Event if: (i) such Party's inability to perform the obligation was caused by its lack of

finances;(ii) such Party's inability to perform the obligation was caused by its deliberate act or inaction; or (iii) such Party failed to provide prompt notice in respect of a Force Majeure Event.

In the event a Party's performance of obligations hereunder (other than payment obligations) is prevented by a Force Majeure Event for a period of more than one hundred twenty (120) calendar days, the unaffected Party may elect to terminate this Agreement. In such case, if the terminating Party is Company, following such termination, Customer shall be liable for the Termination Charges.

18.03 Independent Contractor

(1) Company employees will not be deemed at any time to be employees or servants of Customer and Company is and will remain an independent contractor for all purposes. Unless otherwise agreed to in writing, Company does not undertake to perform any obligation of Customer, whether regulatory or contractual, or to assume any responsibility for Customer's business or operations.

(2) Company and Customer agree and acknowledge that the relationship between Customer and Company is one of owner and independent contractor and not one of employer-employee. Neither is there any intention to create a partnership, joint venture or joint enterprise between Company and Customer.

18.04 No Waiver of Customer Obligations as Employer

Nothing in this Agreement shall be construed in a manner that amounts to a waiver or derogation or transfer to Company, of any of Customer's obligations as an employer, including (but not limited to) with respect Customer's obligations under the *Occupational Health and Safety Act* (Ontario).

18.05 Use of Company Name and Logo.

Customer acknowledges that the name "Enbridge", "Enbridge Gas Distribution Inc." and any names, symbols, signs, trademarks and marks denoting and identifying Enbridge Gas Distribution Inc., its subsidiaries and affiliates, presently in use or acquired from time to time are the property of Company and shall not be used or displayed by Customer in any manner whatsoever without the prior written authorization of Company. Other than as expressly permitted in this Agreement, Customer shall not use, display or utilize any name, logo, sign, symbol, trademark or mark denoting or implying a relationship or affiliation between Customer and Company for any purpose and shall cease such usage upon completion of this Agreement or upon request of Company. Further, Customer shall return to Company forthwith any documents, signs, forms or records provided to it by Company or acquired by Customer in furtherance of this Agreement, upon termination of this Agreement or upon the request of Company. Customer acknowledges and agrees that this undertaking shall continue in effect subsequent to the termination or expiry of this Agreement.

18.06 Severability

The Parties agree that it is the intention of each Party not to violate any public policy or Applicable Laws. To the extent that any provision, portion or extent of this Agreement is deemed to be invalid, illegal or unenforceable, such provision, portion or extent will be severed and deleted or limited so as to give effect to the intent of the Parties insofar as possible and the Parties will use their best efforts to substitute a new provision of like economic intent and effect for the illegal, invalid or unenforceable provision and the remainder of this Agreement, as the case may be, will remain binding upon the Parties.

18.07 Assignment

Customer may not, without Company's prior written consent (which may be withheld in Company's sole discretion), assign or transfer this Agreement, or any of its rights or obligations under this Agreement to any third party (in this Section an "**Assignee**"). Company may assign this Agreement to any third party without the consent of Customer provided that Company notifies Customer in writing of any such assignment.

18.08 Subcontractors

Company may delegate performance of the Services to subcontractors, and Company may disclose to any such subcontractors any information required by them to perform the duties so delegated to them. Company will remain fully liable under this Agreement for the acts and performance by such subcontractors to the same extent as if it was Company itself that had so acted or performed or failed to act or perform, as the case may be, and such work will be deemed to be work performed by Company.

18.09 Waiver and Amendment

No modification, addition to or waiver of any rights, obligations or defaults will be effective unless in writing and signed by the Party against whom the same is sought to be enforced. One or more waivers of any right, obligation or default will not be construed as a waiver of any subsequent right, obligation or default.

18.10 Entire Agreement

This Agreement and all Schedules, appendices, exhibits, attachments, and addenda contemplated herein or specifically referred to herein constitute the entire agreement among the Parties pertaining to all the matters herein, and supersede all prior agreements, understandings, negotiations, discussions and other communications, whether oral or written, of the Parties. Unless otherwise agreed to in writing by the Parties, Customer's use of the Services will be governed by the provisions of this Agreement and the relevant Schedules and Appendices thereto, and nothing contained in any purchase order, letter or other instrument will in any way modify, vary, change or add any provision hereto.

18.11 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein, and the Parties hereby attorn to the exclusive jurisdiction of the courts of the Province of Ontario. The United Nations Convention on Contracts for the International Sale of Goods (1980) does not apply.

18.12 Further Assurances

Each of the Parties hereto will from time to time execute and deliver all such further documents and instruments and do all acts and things as the other Party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement and to establish and protect the rights, interests and remedies intended to be created in favour of the other Party.

18.13 Publicity

Customer's engagement of Company to perform Services will be deemed to constitute Customer's permission for Company to use Customer as a reference in marketing the products and services of Company unless Customer specifically revokes this permission in writing. In no event will either Party publicize or disclose to any third party either the price or other provisions of this Agreement without the consent of the other Party.

[*Remainder of page intentionally left blank*.]

18.14 Counterparts and Delivery

This Agreement may be signed in counterparts, each of which will be deemed to be an original, but all of which taken together, will constitute one and the same instrument. This Agreement may be delivered by electronic transmission, including by email or by facsimile transmission, and if so delivered, this Agreement will be, for all purposes, effective as if the Parties had executed and delivered a manually executed copy of this Agreement. Each Party undertakes to provide the other with a copy of this Agreement bearing original signatures upon request.

IN WITNESS WHEREOF the Parties hereto have executed this Agreement as of the Effective Date.

ENBRIDGE GAS DISTRIBUTION INC.	● ***[INSTRUCTION: insert full legal name of Customer]***
By: _____	By: _____
Authorized Signatory	Authorized Signatory
Name: _____	Name: _____
Title: _____	Title: _____

APPENDIX A
to the Biogas Services Agreement between
Enbridge Gas Distribution Inc. and
● *[INSTRUCTION: Insert full legal name of Customer]*
dated ●

DEFINITIONS

Pursuant to Section 1.01 of the Agreement the following terms shall have the meanings set out below:

(a) "**Affiliate**" means, with respect to any Person, any other Person directly or indirectly controlling, controlled by, or under common control with, such Person as of the date on which the determination of affiliation is being made. For purposes of this definition, the term "control" (including the correlative meanings of the terms "controlled by" and "under common control with"), as used with respect to any Person, means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person by virtue of: (i) the ownership or direction of voting securities of the other Person; (ii) a written agreement or trust instrument; (iii) being the general partner or controlling the general partner of the other Person, or (iv) being the trustee of the other Person;

(b) "**Applicable Laws**" means any and all applicable laws, statutes, by-laws, rules, regulations, orders and ordinances together with all codes, guidelines, policies, notices, directions, directives and standards of any Governmental Authority which are legally mandatory in nature, affecting the obligations of either of the Parties, from time to time;

(c) "**Biogas**" means biogas generated from biomass, including Untreated Biogas, Untreated Biogas that has been upgraded and conditioned but does not meet the Renewable Gas Specification, and Renewable Gas;

(d) "**Business Day**" means any day on which Company's head office in Ontario is open for business as usual;

(e) "**Change in Law**" means the adoption, enactment or promulgation of any new Applicable Laws or the amendment, modification, revision or repeal of any existing Applicable Laws, or the issuance by a Governmental Authority of an order, decision or interpretation of any existing Applicable Laws as a result of which one or more rights or obligations of the Parties under the Agreement are adversely affected in a material manner;

(f) "**Change in Services**" means an adjustment to the Service Fees or other affected provisions of the relevant Schedule(s) (including but not limited to the Performance Requirements), effected by a change order entered into between the Parties;

(g) "**Company Acquired Permits**" has the meaning ascribed thereto in Section 5.06(2)(b);

(h) "**Company Intellectual Property**" means all of the Intellectual Property for the provision of the Services by Company to Customer;

(i) "**Confidential Information**" means the confidential, secret or proprietary information of a Party, its Affiliates or licensors (the "**Disclosing Party**"), including technical, financial and business information of the Disclosing Party which has been or may hereafter be disclosed, directly or indirectly, to the other Party (the "**Recipient**"), either orally, in writing or in any other material form, or delivered to the Recipient, as well as the terms of this Agreement;

(j) "**Commissioning Date**" means the date when the Injection Equipment or the Upgrading Equipment, or (if specified in the Injection Services Schedule and the Upgrading Services Schedule for a Site) both the Injection Equipment and the Upgrading Equipment, at a Site are deemed to have been commissioned into service as determined by Company in its sole discretion and communicated in writing to Customer;

(k) "**Customer Account**" means the Company customer account established for Customer;

(l) "**Customer Acquired Permits**" has the meaning ascribed thereto in Section 5.06(2)(a);

(m) "**Customer Agreements**" means such other agreements for goods and services that are outside the scope of this Agreement, including (i) agreements for the establishment of a Customer Account, (ii) the transportation and delivery of the Renewable Gas and natural gas within Company's distribution system, and (iii) payment of a contribution in aid of construction and/or the provision of financial security, if required, for Company to complete the installation and commissioning of one or more distribution line(s), service line(s), gas meter(s) and/or other upgrades to Company's gas distribution system and related infrastructure;

(n) "**Decommissioning**" means the work and steps associated with decommissioning the Equipment identified on the relevant Schedule;

(o) "**Designated Areas**" means the portions of the Site that are jointly selected by the Parties as the area(s) within which the Injection Equipment and, if applicable, the Upgrading Equipment will be located, as identified on the Site Plan incorporated into the Injection Services Schedule for each Site;

(p) "**Endorsement**", "**Endorsed**" and similar expressions means approval in accordance with the procedures set out in Section 1.05 unless otherwise provided herein;

(q) "**Environmental Attributes**" has the meaning ascribed thereto in Section 2.05;

(r) "**Equipment**" means the equipment installed by Company at a Site to provide the Services, including the facilities, equipment and related infrastructure as further described in the relevant Schedule, and includes the Injection Equipment, the Upgrading Equipment, or both, depending on the Schedules that have been entered into between the Parties;

(s) "**Facility**" has the meaning ascribed thereto in the recitals;

(t) "**Feasibility Services**" has the meaning ascribed thereto in Section 2.01(1);

(u) "**Feasibility Study**" means the feasibility report provided as an output of Feasibility Services in respect of Services or potential Services at a Site, setting out the scope of Services required and the pricing of the Services, including the technical and economic feasibility of the design, equipment procurement, construction, and the operation and maintenance of the Equipment, and incorporating Company's specifications for design, materials and construction;

(v) "**Force Majeure Event**" has the meaning ascribed thereto in Section 18.02;

(w) "**Governmental Authority**" means any national, provincial, state, county, municipal, quasi-governmental or self-regulatory department, authority, organization, agency, commission, board, tribunal, dispute settlement panel or body, bureau, official, minister, Crown corporation, or court or other law, rule or regulation-making entity having or purporting to have jurisdiction over Company, Customer, or any Person, property, transaction, activity, event or other matter related to this Agreement;

(x) "**Injection Equipment**" means the permanent facilities to be wholly supplied, installed, owned and operated by Company pursuant to this Agreement for the provision of the Injection Services;

(y) "**Injection Receipt Point**" means the physical point of delivery downstream of:

(i) the Upgrading Equipment (if Company is providing Upgrading Services at the Site); or

(ii) the upgrading facilities operated by Customer (or its designate),

to the Injection Equipment, and each Injection Receipt Point shall be clearly marked or tagged physically;

(z) "**Injection Services**" has the meaning ascribed thereto in Section 2.01(1);

(aa) "**Intellectual Property Rights**", "**Intellectual Property**" means intellectual property of any nature and kind including all domestic and foreign trade-marks, business names, trade names, domain names, trading styles, patents, trade secrets, software, industrial designs and copyrights;

(bb) "**Latent Site Defects**" include any conditions or circumstances that were not revealed to or ascertained by Company during the due diligence that occurred at the Site (for example, during the Upgrading Equipment Design Analysis conducted pursuant to an Upgrading Services Schedule) . Latent Site Defects include but are not limited to the presence of legally significant cultural resources, endangered species, dangerous site conditions, earthquake fault lines, or air, soil or water contamination;

(cc) "**OEB**" means the Ontario Energy Board, or any successor regulatory entity;

(dd) "**Party**" means Company or Customer, as applicable;

(ee) "**Parties**" means both Company and Customer;

(ff) "**Performance Requirement**" means a performance target for a Service identified as a "Performance Requirement" and defined in a Schedule;

(gg) "**Person**" means any natural person, sole proprietorship, corporation, partnership (general or limited, including master limited), limited liability company, trust, joint venture, joint stock company, unincorporated association, unincorporated syndicate, unincorporated organization, or other entity or association, and, where the context requires, any of the foregoing in its capacity as trustee, executor, administrator or other legal representative;

(hh) "**Rate Handbook**" means Company's 'Handbook of Rates and Distribution Services' as amended, updated or replaced by Company from time to time with approval from the OEB;

(ii) "**Relationship Manager**" has the meaning ascribed thereto in Section 8.02;

(jj) "**Renewable Gas**" means Biogas that has been conditioned or upgraded to a quality meeting the Renewable Gas Specification;

(kk) "**Renewable Gas Specification**" means the renewable gas standards or requirements established by Company, as updated periodically;

(ll) "**Representatives**" means a Party's employees, contractors, consultants and other agents;

(mm) "**Required Orders**" means such grants, permits, licenses, registrations, approvals, consents, waivers, variances, exemptions, filings, authorizations, regulatory consent, credential or similar qualification, orders and decisions or requirements of or by any Governmental Authority having jurisdiction or control over any of the Parties, the Sites or any provision hereof, as are from time to time necessary in order that this Agreement and the performance thereof by the Parties be in compliance with all Applicable Laws;

(nn) "**Schedule**" means a schedule to this Agreement entered into between the Parties subsequent to the execution of this Agreement for the provision of

Services at a particular Site, including an Injection Services Schedule and an Upgrading Services Schedule;

(oo) "**Service Fees**" means all fees payable to Company by Customer pursuant to this Agreement, including the Schedules;

(pp) "**Services**" has the meaning ascribed thereto in Section 2.01;

(qq) "**Site**" has the meaning ascribed thereto in the recitals and, in respect of a particular Schedule, refers to the specific Customer Site identified in the Schedule;

(rr) "**Site Plan**" means the Site Plan attached to the Injection Services Schedule for each Site;

(ss) "**Site Manager**" has the meaning ascribed thereto in Section 8.03;

(tt) "**Term**" has the meaning ascribed thereto in Section 16.01(1);

(uu) "**Termination Charge**" means the termination charge, if any, specified in a Schedule to this Agreement;

(vv) "**Untreated Biogas**" has the meaning ascribed thereto in the recitals;

(ww) "**Upgrading Services**" has the meaning ascribed thereto in Section 2.01(3); and

(xx) "**Upgrading Equipment**" means the permanent facilities to be wholly supplied, installed, owned and operated by Company pursuant to this Agreement for the provision of the Upgrading Services, if any.

APPENDIX B
to the Biogas Services Agreement between
Enbridge Gas Distribution Inc. and
● *[INSTRUCTION: Insert full legal name of Customer]*
dated ●

DESIGNATED AREAS

Save as specifically provided for in a Schedule to this Agreement, the following provisions pertain to rights to be provided by Customer to Company pursuant to this Agreement in respect of each Site that is the subject of a Schedule under this Agreement:

1 DESIGNATED AREAS

1.1 The Designated Areas indicated on each Site Plan shall be fenced and Company shall be entitled to install permanent concrete barriers around the Designated Areas. Customer and its Representatives will only access the Designated Areas if they are accompanied by Company, to perform activities required by Customer pursuant to this Exhibit (e.g. snow removal) or its Representatives or in the event of an emergency and the Company Site Manager is not responsive. Notwithstanding anything in this Agreement to the contrary, Customer's right to enter the Designated Areas shall be subject to any Applicable Laws and to any policies and procedures of Company relating to environmental and health and safety matters ("**EHS Policies**").

1.2 Company shall provide a safety education plan and emergency response plan for the Equipment and the Designated Areas to Customer.

1.3 Company will have access to and entry upon the Site as required:

(i) during regular business hours for the purposes of transporting components of the Equipment to and from the Designated Areas; installing, commissioning, inspecting, maintaining and repairing the Equipment in accordance with the provisions of this Agreement; and decommissioning and removing the Equipment upon termination of this Agreement; and

(ii) at any time, without notice, for the purposes of responding to any emergency involving or otherwise affecting the Equipment, the performance of the Services or the supply of gas (including Untreated Biogas or Biomethane) to the Equipment; making emergency inspections or repairs to the Equipment; and removing any article or remedying any condition which, in the opinion of Company, presents or creates a hazard to the safe operation of the Equipment or the safe performance of the Services.

1.4 Customer shall provide rights-of-way and/or easements as required by Company for Company and its Representatives to construct, install, operate and maintain the Equipment on the Site to serve Customer. In particular, (i) Company and its Representatives shall have a non-exclusive right-of-way along and upon the roads and paved areas of each Site for the purposes of pedestrian and vehicular passage to and

from the Designated Areas; and (ii) Customer will grant Company an easement in Company standard form with respect to Company Injection Equipment (including the underground Equipment).

1.5 At all times and as necessary for Company to perform the Services, Customer shall provide Company with access to the Site, the Designated Areas and the Equipment as described in the Site Plan attached to the Injection Services Schedule for each Site, including unobstructed ready ingress and egress for all personnel, equipment and materials, and vehicles. Customer shall provide an appropriate location at the Site for the delivery of equipment, layout and storage of equipment and materials, ingress and egress and parking of construction related vehicles and the installation, construction, operation and maintenance of the Equipment.

1.6 During the installation of the Equipment and throughout the Schedule Term of each Schedule, Customer shall cooperate with Company and its subcontractors to ensure that the Designated Areas and the immediately surrounding area are kept free and clear of all debris and any other obstructing objects. Customer shall, at its sole cost and expense, remove any such debris and obstructing objects as requested by Company or its subcontractors.

1.7 Customer shall provide ongoing safeguards at the Site for the protection of the Equipment and the provision of the Services, and all persons and other property related thereto, including lights and barriers, guard service, controlled access, and other measures developed pursuant to a continuous safety and security assurance program acceptable to Company, or otherwise reasonably required to prevent vandalism, theft, and danger to the Equipment. Customer shall provide a notice to Company describing Customer's safety and security assurance program no less than thirty (30) days prior to Company commencing construction on a Site.

1.8 Customer shall ensure that each Site, including, but not limited to any access roads, is kept clear of ice and snow during the winter months, slippery surfaces or of any other unsafe condition including but limited to ensuring that approaches to the Designated Areas are cleared of snow and salted throughout the applicable Schedule Term.

1.9 Company will obtain the prior approval of Customer before erecting or installing any permanent signage or display materials on the Site, but Customer shall not withhold such approval unreasonably. Notwithstanding the foregoing, nothing in this Agreement shall restrict or prohibit Company from installing all emergency or safety-related signage and communications on or about the Equipment and the Site, as required by Applicable Laws or Company policy, all of which may be installed by Company without Customer's prior approval. At a minimum, Company shall erect or install permanent signage on or near the Equipment pertaining to the avoidance of smoking about or near the Equipment, restricting use and access to the Equipment by authorized and appropriately trained personnel and the display of an emergency telephone number to call in the event of a gas leak or other emergency.

1.10 Following the Commissioning Date of the Equipment and from time to time thereafter, in the event of an emergency or a bona fide perceived emergency, Company shall be permitted to make any and all alterations or additions it deems necessary to the

Designated Areas or the facilities located thereon, from time to time, without the prior written approval of Customer. At all other times, no alterations will be made except with the written consent of Customer, such consent not to be unreasonably withheld, delayed or conditioned. All such alterations or additions shall be made in a good and workmanlike manner. Subject to the foregoing, Company shall take all commercially reasonable efforts to: (i) consult with Customer prior to any repair to the facilities within the Designated Areas; and (ii) to minimize disruption to Customer and its transit operations.

1.11 Customer shall provide Company with access rights required by Company to effect the removal of any and all of the Equipment or any other of Company's assets installed on or below the Site after the expiration or earlier termination of a Schedule.

2 LIENS BY COMPANY

2.1 Company shall comply with all the provisions of the *Construction Lien Act* (Ontario) and other statutes from time to time applicable thereto (including any provision requiring or enabling the retention of portions of any sums payable by way of holdbacks). If and when any builder's or other lien for work, labour, services or materials supplied to or for Company or for the cost of which Company may be in any way liable or claims therefor shall arise or be filed, Company shall within twenty (20) days after receipt of notice thereof procure the discharge thereof, including any certificate of action registered in respect of any lien, by payment or giving security or in such other manner as may be required or permitted by law, and failing which Customer may make any payments into court (but not in any event to the lien claimant) required to procure the discharge of any such liens, shall be entitled to be reimbursed by Company within fourteen (14) calendar days, and its right to reimbursement shall not be affected or impaired if Company shall then or subsequently establish or claim that any lien so discharged was without merit or excessive or subject to any abatement, setoff or defence.

3 OWNERSHIP OF EQUIPMENT

3.1 Company shall retain sole and exclusive title in and to the Equipment at all times while the relevant Schedule remains in effect, notwithstanding that they may be annexed or affixed to the premises. The Equipment may be removable in whole or in part by Company without the consent of Customer.

3.2 Customer shall not, under any circumstances, permit any third party to attach or perfect any lien, security interest, mortgage, charge or other encumbrance (each, an "**Encumbrance**") over the Equipment. Customer shall promptly notify Company upon receipt of any notice from a third party that alleges, asserts or claims to hold, an Encumbrance over the Equipment.

3.3 Company shall be entitled to label the Equipment to designate that the Equipment is owned by Company and Customer shall not remove or tamper in any way with such labelling.

3.4 Only personnel duly authorized by Company are allowed to connect or disconnect the Equipment, remove the Equipment or perform any work upon Company-owned facilities, including the Equipment.

3.5 Customer shall not frustrate or otherwise restrict Company's efforts to protect or otherwise assert its proprietary rights in and to the Equipment. Without limiting the generality of the foregoing, Customer hereby consents to the registration by Company of a notice of its interest in the Equipment pursuant to the *Personal Property Security Act* (Ontario), and filing in the public records, including real estate records, such instruments as Company may consider to be appropriate.

4 ENVIRONMENTAL

[INSTRUCTION: may be revised to reflect Site conditions.] Customer represents and warrants that the Site has not been used for the storage of and does not contain any toxic, hazardous, dangerous, noxious or waste substances or contaminants (collectively the "**Hazardous Substances**"). If Company encounters Hazardous Substances in undertaking any work it shall give notice to Customer. At the expense of Customer, Company shall effect the removal of such Hazardous Substances in accordance with Applicable Laws.

APPENDIX C
to the Biogas Services Agreement between
Enbridge Gas Distribution Inc. and
● *[INSTRUCTION: Insert full legal name of Customer]*
dated ●

FORM OF FEASIBILITY SERVICES SCHEDULE

[Please see attached.]

FEASIBILITY SERVICES SCHEDULE
(Site: [●])

THIS FEASIBILITY SERVICES SCHEDULE is entered into as of the * day of *, 20___ (the "**Schedule Effective Date**") pursuant to the Biogas Services Agreement made as of [*] between Enbridge Gas Distribution Inc. ("**Company**") and ● ***[INSTRUCTION: Insert full legal name of Customer]*** ("**Customer**"), as amended from time to time (the "**Agreement**"). Unless otherwise provided below, this Schedule incorporates all of the terms and conditions of the Agreement.

WHEREAS:

1.1 In respect of Customer's Facility at ***[INSTRUCTIONS: insert municipal address]*** (the "**Site**"), Customer has expressed interest in Company providing: (i) Injection Services; or (ii) both Injection Services and Upgrading Services, at the Site ("**Additional Services**"). Company and Customer agree that it will be necessary for Company to engage in preparatory work, including incurring certain costs and expenses, to facilitate the entering into of the Schedules pertaining to Additional Services.

1.2 The purpose of this Schedule is to set out the nature and extent of preparatory work to be performed by Company, including the preliminary costs and expenses which will be incurred by Company for such preparatory work and which is to be reimbursed by Customer to Company, and the mechanism for doing so.

1 INTERPRETATION

1.1 Definitions. All capitalized terms used in this Schedule and not otherwise defined will have the meaning given to them in the Agreement. In this Schedule:

"**Schedule**" means this Schedule, including all Appendices and Exhibits attached to this Schedule and any other documents expressly incorporated by reference herein, as amended (by Change Order or otherwise) from time to time in accordance with this Schedule.

"**Schedule Term**" has the meaning given to it in Section 2.1.

1.2 Exhibits. The following are the Exhibits to this Schedule as of the Schedule Effective Date:

Exhibit C1 – Examples of the Scope of Feasibility Services

2 TERM AND TERMINATION

2.1 Term. The term of this Schedule will begin on the Schedule Effective Date and continue until [●] (the "**Schedule Term**"), unless terminated earlier in accordance with the Agreement.

2.2 Termination. In addition to the termination rights set out in Article 16 of the Agreement, this Schedule may be terminated by either Company or Customer at any time upon written notice to the other Party.

2.3 Survival. The provisions of the Agreement identified in Section 16.04 of the main body of the Agreement and incorporated by reference herein and the provisions of this Schedule requiring performance or fulfilment after the expiration or earlier termination of this Schedule, this Section 2.3, such other provisions as are necessary for the interpretation thereof, and any other provisions hereof, the nature and intent of which is to survive termination or expiration of this Schedule, will survive the expiration or earlier termination of this Schedule.

3 DESCRIPTION OF THE SERVICES

3.1 Scope of Feasibility Services. Company shall determine the scope of the Feasibility Services (the "**Scope of Feasibility Services**"). A non-exhaustive list of examples of Feasibility Services that may be undertaken is included in Exhibit C1 to this Schedule. Company will determine, in its sole discretion, whether prior work done by Company and/or Customer can be used to fulfill the purposes of this Schedule.

3.2 Acknowledgement. Company and Customer acknowledge and agree that: (1) Company shall exercise its independent, professional and trade judgment in performing the Services; and (2) in its preparation of the Scope of Feasibility Services, Company will be relying on information provided by Customer, which Customer represents is complete and accurate except as noted in writing to Company. Company shall not, except as may be provided for in an executed Additional Services Schedule, be required to deliver to Customer any of the information, reports, documents or other results which arise from the Feasibility Services.

3.3 Work Product. The results and outcomes of the Feasibility Services (the "**Work Product**"), except for that portion of the Work Product, if any, provided by Customer to Company, shall be Company Intellectual Property.

4 CUSTOMER OBLIGATIONS

4.1 Reimbursement. On the terms and subject to the conditions set out in the Agreement and this Schedule, Customer agrees to reimburse Company for all reasonable costs and expenses incurred by Company as contemplated and provided for in this Schedule (including reasonable costs and expenses associated with pre-existing materials for which Customer's project constitutes an Alternate Purpose, the "**Qualifying Expenses**").

4.2 Provision of Information. At Company's request from time to time, Customer will provide such information to Company as is required to facilitate the Feasibility Services including, without limitation, by providing Company with access to information, documents, materials and personnel. Without limitation, Customer will provide Company with the following information:

(a) gas quantity and quality specifications of Untreated Biogas that would be subject to the Upgrading Services; and

(b) [*].

Customer represents and warrants that all information provided to Company pursuant to this Schedule shall be true and accurate, to the best of Customer's knowledge.

5 SERVICE FEES

5.1 Qualifying Expenses. The Qualifying Expenses incurred by Company under this Schedule in connection with the Feasibility Services shall not exceed $[●] without the prior written approval of Customer.

5.2 Increase to Qualifying Expenses. If Company determines that it is necessary to incur Qualifying Expenses over and above the amount set out in Section 5.1, then it shall provide a written notice of same to Customer, accompanied by a description of the expenditure, the rationale for the expenditure, and the amount of the expenditure. Unless the notice sets out a longer period, Customer shall respond to Company in writing within five (5) Business Days' of delivery of such notice and shall set out either its further requests and questions in respect of such proposed expenditure, or its approval thereof. Upon approval by Customer, any such expenditure shall be a Qualifying Expense hereunder. The Customer acknowledges that its failure to approve a proposed expenditure in writing within the required time period may result in a delay to the Feasibility Services.

5.3 Effect of Additional Services Schedule. If the Parties execute an Additional Services Schedule (or Schedules) for the Site, then the Qualifying Expenses will constitute part of the final project costs and factor into the determination of Service Fees to be paid by Customer for the Additional Services. In such instance, all Qualifying Expenses shall be governed by the Additional Services Schedule(s).

5.4 Invoice. Upon notice by Customer to Company that it no longer intends to proceed with Additional Services, or an Additional Services Schedule has not been executed by [*] (or such later date as the Parties may agree to in writing), Company will invoice Customer for all Qualifying Expenses. Notwithstanding Section 4.02 of the Agreement, all Qualifying Expenses shall be paid by Customer within thirty (30) days of receipt of an invoice from Company for such Qualifying Expenses. Company will provide Customer with such documentation as Customer may reasonably require confirming the nature and quantum of the Qualifying Expenses so incurred.

6 ALTERNATE USE OF WORK PRODUCT

6.1 Alternate Purposes. Company may use the Work Product for other potential customers or for Company's own business purposes (the "**Alternate Purposes**"). Notwithstanding the foregoing, the Parties agree that Company is under no obligation to use the Work Product for Alternate Purposes and that the Work Product may never be used for any Alternate Purposes.

6.2 Reimbursement. In the event that the Parties do not execute any Additional Services Schedules and Company determines, acting reasonably, that: (i) it is able to use the Work Product for Alternate Purposes, and (ii) it is able to recover all or part of the cost of such Work Product which has been paid for by Customer under this Schedule; then Company shall determine the amount of Qualifying Expenses paid by Customer, if any, that should be reimbursed to Customer (the "**Reimbursement Amount**"). In the event that Company determines that a Reimbursement Amount is due to Customer under this Section, it shall notify Customer in writing and pay such Reimbursement Amount to Customer within thirty (30) days of the date of such notice.

6.3 Obligation Term. Company's obligations under this Section shall expire one (1) year from the date of the expiration or termination of this Schedule. For greater certainty, in the event that the Work Product has not be used for any Alternate Purposes or Company has determined that no Reimbursement Amount is owing under this Section within such one (1) year period, this Section shall thereafter be of no force or effect.

6.4 Determination. The Parties agree that so long as Company has not acted in bad faith in determining whether a Reimbursement Amount is applicable, or in calculating any Reimbursement Amount that may be applicable, Company's obligations under this Section shall be limited to the payment to Customer of the Reimbursement Amount, if any, payable hereunder.

7 OTHER TERMS

[*]

IN WITNESS WHEREOF the Parties hereto have executed this Schedule as of the Schedule Effective Date.

ENBRIDGE GAS DISTRIBUTION INC.	● ***[INSTRUCTION: insert full legal name of Customer]***
	By: _____
_____	_____
Authorized Signatory	Authorized Signatory
Name: _____	Name: _____
Title: _____	Title: _____

Exhibit C1 – Examples of the Scope of Feasibility Services

Company shall retain an engineering consultant (the "**Engineering Consultant**"). Company will regularly update and be fully transparent to Customer as to the costs arising out of the Engineering Consultant's retainer.

The Engineering Consultant will:

(a) determine the technical and economic feasibility of the design, equipment procurement, construction, operation and maintenance of biogas upgrading and conditioning equipment as necessary to treat the Untreated Biogas from the Facility to create Renewable Gas,

(b) provide sufficient information to prepare the scope of work and pricing for further schedules to the Agreement;

(c) create the engineering documents and tender documents that are specific to the design of the Equipment and its installation and operation at the Site; and

(d) such other work as may be approved in accordance with this Schedule.

APPENDIX D
to the Biogas Services Agreement between
Enbridge Gas Distribution Inc. and
● *[INSTRUCTION: Insert full legal name of Customer]*
dated ●

FORM OF INJECTION SERVICES SCHEDULE

(Note: there are two forms of this Appendix:
D.1 – Company Providing Upgrading Services
D.2 – Company not Providing Upgrading Services)

[Please see attached.]

INJECTION SERVICES SCHEDULE

(Company Providing Upgrading Services)

(Site: [●])

THIS INJECTION SERVICES SCHEDULE is entered into as of the ● day of ●, 20___ (the "**Schedule Effective Date**") pursuant to the Biogas Services Agreement made as of [●] between Enbridge Gas Distribution Inc. ("**Company**") and [●] ***[INSTRUCTION: Insert full legal name of Customer]*** ("**Customer**"), as amended from time to time (the "**Agreement**"), with respect to the provision of Injection Services pertaining to Customer's Facility at ***[INSTRUCTIONS: insert municipal address]*** (the "**Site**"). Unless otherwise provided below, this Schedule incorporates all of the terms and conditions of the Agreement.

1 INTERPRETATION

1.1 Definitions. All capitalized terms used in this Schedule and not otherwise defined will have the meaning given to them in the Agreement. In this Schedule:

(a) "**Commissioning Date**" means the date when the ***[INSTRUCTION: confirm the Upgrading Equipment and the Injection Equipment will have the same Commissioning Date at this specific site.]*** Upgrading Equipment and the Injection Equipment at the Site are deemed to have been commissioned into service as determined by Company in its sole discretion and communicated in writing to Customer;

(b) "**Contract Year**" means a 12 month period beginning on the Commissioning Date during the first Contract Year and on the anniversary date of the Commissioning Date for all subsequent Contract Years;

(c) "**Day**" shall mean a period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Standard Time. The reference date for any Day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

(d) "**Delivery Point**" means Company's Eastern Delivery Area ("**EDA**"), or Company's Central Delivery Area ("**CDA**") as defined in TransCanada Pipeline Limited's tariff as approved by the National Energy Board, as more specifically set out in Exhibit D1;

(e) "**Eastern Standard Time**" means Eastern Standard Time at Toronto, Ontario; and which, for certainty, includes any adjustment for Daylight Savings Time;

(f) "**Injection Receipt Point**" means the physical point of delivery downstream of the Upgrading Equipment to the Injection Equipment; each Injection Receipt Point shall be clearly marked or tagged physically;

(g) "**Market Quantity**" shall mean the daily quantity of Renewable Gas in GJ nominated on that Day by Customer;

(h) "**Nomination**" means a written or electronic request from Customer regarding a quantity of Renewable Gas that Customer intends to deliver to Company

pursuant to this Agreement, or otherwise transfer or assign in a manner contemplated in this Agreement;

(i) "**PGA Range**" has the meaning ascribed thereto in Exhibit D7 attached hereto;

(j) "**Produced Quantity**" or "**PQ**" is measured in GJ and is the product of:

Produced Volume (10^3m^3) x Producer Heat Value ($GJ/10^3m^3$);

(k) "**Produced Volume**" means the aggregate of all actual volumes of Renewable Gas in 10^3m^3, delivered to the Injection Receipt Point on any Day;

(l) "**Producer Gas Account**" or "**PGA**" means the producer gas account created by Company to facilitate balancing of the Market Quantity and the Produced Quantity.

(m) "**Producer Heat Value**" means the heat content as set by Company, and shall be determined in accordance with Company's policies and procedures;

(n) "**Schedule**" means this Schedule, including all Exhibits attached to this Schedule and any other documents expressly incorporated by reference herein, as amended from time to time in accordance with this Agreement;

(o) "**Schedule Term**" has the meaning given to it in Section 2.1; and

(p) "**System Capacity**" shall mean the volumetric capacity that exists from time to time within Company's pipeline and distribution system, as determined by Company in its sole discretion.

1.2 Exhibits. The following are the Exhibits to this Schedule as of the Schedule Effective Date:

Exhibit D1	–	Contract Parameters
Exhibit D2	–	Conditions Precedent
Exhibit D3	–	Required Orders
Exhibit D4	–	Construction Phase: Company and Customer Work
Exhibit D5	–	Service Fees
Exhibit D6	–	Termination Charge
Exhibit D7	–	Producer Gas Account Balancing
Exhibit D8	–	Site Plan

2 TERM AND TERMINATION

2.1 Term. The term of this Schedule shall be effective as of the Schedule Effective Date and continue for a term of [***INSTRUCTIONS: insert term.*** ●(●)] years commencing from the Commissioning Date (the "**Schedule Term**), unless terminated earlier in accordance with the Agreement.

2.2 Termination. Subject to the other provisions of this Schedule, this Schedule may be terminated by Company at any time (i) in accordance with Section 6.02 or Section 16.02 of the Agreement,or (ii) if Customer terminates the Upgrading Services Schedule applicable the Site. *Upon the termination of this Schedule, any related Schedule for Upgrading Services (e.g. any Upgrading Services Schedule associated with the Site) shall also terminate.*

2.3 Termination Charge. The Termination Charge payable pursuant to this Schedule is specified in Exhibit D6.

2.4 Survival. The provisions of the Agreement identified in Section 16.04 of the main body of the Agreement and incorporated by reference herein and the provisions of this Schedule requiring performance or fulfilment after the expiration or earlier termination of this Agreement, this Section 2.4, such other provisions as are necessary for the interpretation thereof, and any other provisions hereof, the nature and intent of which is to survive termination or expiration of this Agreement, will survive the expiration or earlier termination of this Schedule.

3 CONDITIONS PRECEDENT

The conditions precedent applicable to this Schedule are set out in Exhibit D2.

4 DESCRIPTION OF INJECTION SERVICES

4.1 Provision of Injection Services. Company will provide the Injection Services on the following basis, consistent with the Feasibility Study for the Site:

(a) Company shall be responsible for planning, designing, procuring, installing, constructing, engineering, commissioning, operating and maintaining Equipment of suitable capacity and design as is required for Company to provide the Injection Services in accordance with this Schedule and the Agreement;

(b) the Injection Equipment shall be owned by Company and operated and maintained by Company and/or its contractors or agents;

(c) Customer shall deliver, or cause to be delivered, the Produced Volume, up to the Maximum Produced Volume per Day (10^3m^3) during the Schedule Term at the Injection Receipt Point;

(d) Company agrees to accept delivery of the Produced Volume, on a reasonable efforts basis, at the Injection Receipt Point provided that:

(i) Company has sufficient System Capacity to receive the gas offered for delivery by Customer; and

(ii) such gas meets the Renewable Gas Specification;

(e) Company shall deliver at the Delivery Point a Market Quantity provided Customer has tendered its daily quantity Nomination in accordance with Section 5 of this Schedule;

(f) in the event that there is insufficient System Capacity, Company will not be able to accept the Produced Volume pursuant to this Schedule, and no remedy will be available;

(g) if the Biogas delivered at the Injection Receipt Point fails to conform to the Renewable Gas Specification, Company, in addition to its other remedies, may refuse to accept delivery of such Biogas at the Injection Receipt Point; and

(h) each Party agrees to forthwith notify the other verbally, followed by written notification, if the Biogas provided by Customer at the Injection Receipt Point does not meet the Renewable Gas Specification.

5 NOMINATIONS

(a) Processes. Customer shall use the processes and mechanisms designated from time to time by Company to submit its Nominations for Market Quantity. Customer may provide notice of Nominations as indicated in Exhibit D1. Customer acknowledges that a further corresponding nomination may be required pursuant to any relevant Customer Agreements with Company.

(b) Submittal. Customer shall submit to Company Nominations in accordance with the North American Energy Standards Board ("**NAESB**") standards and at the nomination times (the "**Nomination Times**") set out therein. Valid Nominations must be submitted regularly, failing which the last regular Nomination accepted by Company shall be considered as a standing Nomination applicable to each subsequent Day until varied by Customer.

(c) Acceptance. Acceptance by Company of any Nomination from Customer shall be subject to the other terms and provisions of this Agreement, and is contingent upon the confirmation and actual delivery of the Produced Volume. A Nomination shall only be deemed to be accepted by Company upon issuance of an electronic communication to Customer providing notice of such acceptance.

(d) Revision. Customer shall have the opportunity, subject to acceptance by Company, to revise a Nomination by further notice or notices given to Company, provided that (i) such notice or notices must be given in accordance with the applicable Nomination Times; and (ii) Customer must comply with the other terms and conditions of this Section 5 regarding revisions to the Nomination.

(e) Company Remedies. If Customer does not nominate in accordance with this Section 5, Company may, in addition to its other rights and remedies available under the Agreement or at law, suspend further performance of the Injection Services under this Schedule, and any Upgrading Services under an Upgrading Services Schedule for the Site, if any, or, in the alternative, terminate this Schedule and any Upgrading Services Schedule for the Site.

6 PRODUCER GAS ACCOUNT BALANCING

6.1 Producer Gas Account. Customer and Company acknowledge that the Producer Heat Value may be greater or less than the energy value associated with Company system gas, and that adjustments will be required to reflect any difference between the Produced Quantity and the Market Quantity. In addition, there may also be differences between the Nominations and the amount produced. To facilitate such adjustments, Company shall establish and maintain on behalf of Customer a Producer Gas Account.

6.2 Producer Gas Account Balancing. Producer Gas Account balancing services will provided in accordance with Exhibit D7. Exhibit D7 may be amended by Company from time to time upon ninety (90) days' notice to Customer.

6.3 Commingling. Company shall have the right to commingle the quantity of Renewable Gas referenced herein with gas owned by Company or gas being stored and/or transported by Company for third parties.

7 EQUIPMENT ON CUSTOMER'S PROPERTY

7.1 Location. The Injection Equipment shall be installed at Customer's premises in the portion of Customer's Site as indicated on the Site Plan attached at Exhibit B8. Customer shall provide such rights in, and access to Customer's Site and Facility as may be required by Company for the purposes of performing the Services as further set out in Appendix B (Designated Areas) to the Agreement.

7.2 Equipment. The Equipment comprising the Injection Equipment shall be determined by Company in its sole discretion. The Equipment shall generally consist of: a moisture analyzer and gas chromatography, compression, telemetry, metering, odourization and regulator equipment. The Injection Equipment are subject to change in Company's sole discretion, from time to time. Customer agrees that Sections 2.03 and 7.01(4) of, and Appendix B (Designated Areas) to, the Agreement applies in respect of such Equipment.

8 OBLIGATIONS OF CUSTOMER

8.1 Cooperation. Customer shall cooperate with Company to facilitate the provision of the Services pursuant to this Schedule, including the installation, construction, commissioning, operations and maintenance of the Injection Equipment.

8.2 Customer Acquired Permits and Work. Customer shall obtain the Customer Acquired Permits set out in Exhibit D3, and perform the Customer work identified in Exhibit D4, at Customer's own cost and expense.

8.3 Customer Operating Obligations. Customer shall be responsible for the following operating obligations, at its own cost and expense:

(a) a flare located at Customer's facility upstream of the Injection Equipment that receives and flares gas from the Injection Equipment, and access to the flare, and Customer will ensure the flare is in good working order and of sufficient capacity to meet the requirements communicated by Company; and

(b) any electrical or other connections reasonably required for the Equipment, including a continuous supply of electrical power at 110 volts.

8.4 Customer's Facility. Customer shall commission and operate the Customer's Facility.

8.5 Maintenance or Shut-Down by Customer. Customer will provide Company with:

(a) an annual schedule of planned preventative maintenance and shutdown activities for the Customer's Facility by January 31 of each calendar year (and, if the Commissioning Date occurs other than on January 1 of a calendar year, within 30 days of the Commissioning Date);

(b) with respect to any changes to the annual schedule, at least three months' notice of such changes; and

(c) immediately provide notice in the case of an unscheduled shut-down by Customer of the Customer's facilities that produce Untreated Biogas.

8.6 Annual Forecast. Customer shall provide to Company not less than sixty (60) days prior to the commencement of each Contract year an annual forecast of the Produced Volume and the Untreated Biogas volume in cubic meters identifying expected daily flows, expected down times and anticipated peak production periods. For certainty, Company shall have no obligation to accept gas from Customer in accordance with any such annual forecast.

8.7 Declaration. Upon request by Company, Customer shall provide to Company a declaration (in a form acceptable to Company) that the Biogas provided at the Upgrading Receipt Point (as defined in the Upgrading Services Schedule for the Site) is derived from biomass for the purposes of GHG reporting pursuant to the *Climate Change Mitigation and Low-carbon Economy Act, 2016*, S.O. 2016, c.7 and regulations.

9 ADDITIONAL OBLIGATIONS OF COMPANY

9.1 Company Acquired Permits. Company shall be responsible for obtaining the Company Acquired Permits set out in Exhibit D3, and performing the Company work identified in Exhibit D4.

9.2 Decommissioning Process. Upon the expiration or termination of this Agreement, Company shall be responsible for safely decommissioning and removing the Injection Equipment and all of the improvements made pursuant to this Agreement by Company; provided that (i) Company shall have no obligation to remove the permanent civil structures (e.g. the concrete pad) upon which the Equipment is installed, nor to undertake any remedial work [***INSTRUCTIONS: if the Site has unique Decommissioning obligations, please add a "Decommissioning Obligations" Exhibit by including the following language, adding an Exhibit at the end of this document and amending the list of Exhibits in Section 1.2 to include the Decommissioinng Obligations Exhibit: (other than the Decommissioning Obligations itemized in Exhibit ●)]*** to return the Site to its original condition prior to the installation of the Equipment; (ii) gas lines at the Site (including underground gas lines) will be disconnected (in the case of underground gas lines, cut at grade level) and abandoned in place but purged and capped; and (iii) metal structures (such as water

pipes and electrical services) will not be removed by Company. All costs associated with Decommissioning will be charged to Customer. Customer shall allow Company a sufficient amount of time to complete the removal of the Injection Equipment and related facilities.

10 CONTROL AND POSSESSION OF BIOGAS

10.1 Customer and Company acknowledge that they have entered into an Upgrading Services Schedule for Upgrading Services at the Site. The Parties agree that:

(a) Customer shall be deemed to be in control and possession of, and responsible for, the Biogas until it shall have been delivered to Company at the Upgrading Receipt Point (as defined in the Upgrading Services Schedule) pursuant to the Upgrading Services Schedule for the Site and shall bear the full cost and expense for delivering the Biogas to the Upgrading Receipt Point; and

(b) upon delivery at the Upgrading Receipt Point and until delivery to the Delivery Point, Company shall be deemed to be in control and possession of, and responsible for, such Biogas.

11 CURTAILMENT AND SUSPENSION

11.1 In the event of actual or threatened inability to provide the Injection Services under this Schedule by Company due to a Force Majeure Event affecting Company or when curtailment or discontinuance of gas supply is ordered by a Governmental Authority, Customer shall, at the direction of Company, make arrangements to cease deliveries of Renewable Gas and Untreated Biogas and shut down the operation of Customer Facility as needed by Company during the period specified by Company (by notice to Customer in accordance with the other terms of this Agreement). Company shall not be liable, in any event, for any damages, losses, costs or expenses incurred or suffered by Customer by reason of any such curtailment or discontinuance or because of the length of advance notice given directing such curtailment or discontinuance.

11.2 Company may be required from time to time to perform maintenance or construction to its facilities (including the Upgrading Equipment, the Injection Equipment and Company's gas distribution facilities) which may impact Company's ability to meet Customer's requirements, or Company's obligations, set out in this Schedule. In such event, except in cases of emergency, Company shall have the right to suspend service under this Agreement in whole or in part; provided that Company and Customer, each acting reasonably, determine a mutually acceptable period during which such maintenance or construction will occur. For certainty, in cases of emergency no prior notice or consultation by Company shall be required to perform any required maintenance or construction, provided Company shall use reasonable efforts to inform Customer of the nature, extent and timing of such emergency. In all cases, Company shall use reasonable efforts to limit the extent and duration of any service interruption hereunder. During any such service interruption, (i) Customer shall shut down the operation of any Customer Facility and systems as needed by Company; and (ii) in cases of emergency, Customer will be required to pay only prorated Service Fees, as determined by Company in its sole discretion, but such prorating shall not affect any other contracts or agreement for services between Company and Customer.

12 REPRESENTATIONS AND WARRANTIES OF CUSTOMER

12.1 In addition to any other representations and warranties given to Company under this Agreement, Customer represents and warrants to Company that at the date hereof and at all times during the Schedule Term:

(a) there are no latent defects at the Premises that will impede Company from obtaining the Company Acquired Permits,

(b) [***INSTRUCTIONS: insert any project-specific reps and warranties that are necessary***]

and acknowledges and agrees that Company is relying on the accuracy of each of such representations and warranties in connection with the entering into of this Agreement and the acceptance by Company of all Renewable Gas from Customer.

13 SERVICE FEES

13.1 Commencing as of ***[INSTRUCTIONS: to confirm - the Commissioning Date]*** and continuing throughout the Schedule Term, Customer shall pay Company the Service Fees set out in Exhibit D5.

13.2 The Service Fees for the first month immediately after the Commissioning Date may be invoiced on a pro-rata basis or deferred until a subsequent month or invoice for the purposes of aligning the Service Fees with the invoice period for the supply of natural gas pursuant to the Customer Account.

13.3 The Service Fees shall be payable in accordance with Section 4.02 of the Agreement.

13.4 If an invoice remains unpaid past the period established in Section 4.02 of the Agreement, Company may, in addition to its other rights and remedies available under the Agreement or at law, suspend further performance of the Injection Services under this Schedule until such invoice is paid or, in the alternative, terminate this Schedule.

[*Remainder of page intentionally left blank*.]

14 GENERAL

14.1 This Schedule may be signed in counterparts, each of which will be deemed to be an original, but all of which taken together, will constitute one and the same instrument. This Schedule may be delivered by electronic transmission, including by email or by facsimile transmission, and if so delivered, this Agreement will be, for all purposes, effective as if the Parties had executed and delivered a manually executed copy of this Agreement. Each Party undertakes to provide the other with a copy of this Agreement bearing original signatures upon request.

IN WITNESS WHEREOF the Parties hereto have executed this Schedule as of the Schedule Effective Date.

ENBRIDGE GAS DISTRIBUTION INC.

● ***[INSTRUCTION: insert full legal name of Customer]***

By: _____

Authorized Signatory

Name: _____

Title: _____

Authorized Signatory

Name: _____

Title: _____

Authorized Signatory

Name: _____

Title: _____

EXHIBIT D1 – CONTRACT PARAMETERS

The following table sets out the contract parameters and notice requirements for Nominations:

Contract Parameter	Details
Site	[●municipal address]
Delivery Point	The gas production site measured by Company's meter located at [Lot___, Concession___, _____Township, _____ County, Province of Ontario, Station #_____]
Producer Heat Value	The deemed Producer Heat Value as of the Commissioning Date is: [●]
Maximum Produced Volume per Day	[●] 10^3m^3
Allowable Operating Pressure	Minimum: [●] kPa Maximum: [●] kPa The pressure of the Untreated Biogas delivered by, or caused to be delivered by, Customer to Company at the Upgrading Receipt Point shall be sufficient to move gas into Company's pipeline, and shall be at least the minimum specified above but shall not exceed the maximum limit specified above. Company may change the allowable operating pressure from time to time and Company shall provide to Customer six (6) months' notice of such change.
PGA Range	[●]
Notice for Nominations	gascontrol@enbridge.com

EXHIBIT D2– CONDITIONS PRECEDENT

D2.1 The obligations of Company to provide the Services pursuant to this Schedule are subject to the following conditions precedent:

(a) Company shall have obtained, in form and substance satisfactory to Company, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders, and authorizations that are required to:

(i) construct and operate the Equipment; and

(ii) provide the Services,

under a regulatory framework satisfactory to Company, in its sole discretion; and

(b) each of the Parties shall have received all Required Orders for the construction and operation of the Customer's Facility and the Equipment at the Site

D2.2 The obligations of Company to provide the Services pursuant to this Schedule are subject to the following conditions precedent, which are for the sole benefit of Company and which may be waived in whole or in part by Company:

(a) Company shall have completed and placed into service the facilities and equipment necessary to provide the Services hereunder;

(b) Company, where applicable, shall have received from Customer executed Customer Agreements; and

(c) Customer shall have provided Company with notice that Customer has: (i) obtained all Customer Acquired Permits pertaining to the Services, and (ii) the Customer's Facility and related infrastructure is commissioned.

EXHIBIT D3 – REQUIRED ORDERS

[INSTRUCTION: To be completed.]

EXHIBIT D4 – CONSTRUCTION PHASE: COMPANY AND CUSTOMER WORK

[INSTRUCTION: To be completed.]

EXHIBIT D5– SERVICE FEES

Customer shall pay to Company the following Service Fees in respect of the Services provided by Company to Customer pursuant to this Schedule.

Customer will pay a Service Fee on a monthly basis (the "**Monthly Service Fee**"), determined in accordance with the following:

D5.1 INITIAL MONTHLY SERVICE FEE

The following fee (the "**Initial Monthly Service Fee**") will be invoiced to Customer from and after the Commissioning Date. The Initial Monthly Service Fee is based on Company's initial estimates of the capital, operating and financing cost requirements (and applicable taxes) of the Injection Equipment:

Initial Monthly Service Fee: $[●], plus applicable taxes

D5.2 DETERMINATION OF MONTHLY SERVICE FEE AND TRUE-UP OF INITIAL MONTHLY SERVICE FEE

(a) As of and from the Commissioning Date until the Monthly Service Fee is settled in accordance with this Section D5.2, Customer will pay the Initial Monthly Service Fee as set out above.

(b) Within twenty (20) Business Days of the 6 month anniversary of the Commissioning Date, Company will prepare and deliver to Customer a notice setting out the Monthly Service Fees, recalculated on the basis of the actual costs incurred by Company, and the Monthly Service Fee for the remainder of the Term will be invoiced in accordance with the Monthly Service Fee set out in the notice (subject to amendment in accordance with the Agreement and this Schedule).

(c) If the Monthly Service Fee in the notice exceeds the Initial Monthly Service Fee, Company will, within two (2) billing cycles of such determination, debit the monthly invoice issued by Company to Customer for the Services for an amount equal to such difference multiplied by the number of billing cycles in respect of which Customer was charged the Initial Monthly Service Fee. If the Monthly Service Fee as so determined is less than the Initial Monthly Service Fee, Company will, within two (2) billing cycles of such determination, credit the monthly invoice issued by Company to Customer for the Services for an amount equal to such difference multiplied by the number of billing cycles in respect of which Customer was charged the Initial Monthly Service Fee.

EXHIBIT D6 - TERMINATION CHARGE

D6.1 TERMINATION CHARGE PRIOR TO COMMISSIONING DATE

For purposes of calculating the Termination Charge in the event of a termination prior to the Commissioning Date, the Termination Charge will be calculated by Company based upon the aggregate of all internal and external costs, expenses and overheads incurred by Company up to, and resulting from, the termination, including but not limited to those relating to: site and station design and studies, permitting fees, site preparation, construction, material, equipment, third party parts and components, maintenance, decommissioning, site and station restoration and associated cancellation fees up to an amount that will not exceed the Termination Charge for Contract Year 1 as set out in the table below.

D6.2 TERMINATION CHARGE AS OF AND FROM THE COMMISSIONING DATE

Contract Year during which Termination Occurs*	Termination Charge
1	[●]
2	[●]
3	[●]
4	[●]
5	[●]
6	[●]
7	[●]
8	[●]
9	[●]
10	[●]

* For greater certainty, the Termination Charge will decrease each Contract Year following the first Contract Year as shown in the above table.

D6.3 DETERMINATION OF TERMINATION CHARGE

As of and from the Commissioning Date until the Monthly Service Fee is settled in accordance with Exhibit D5, the Termination Charge will be the Termination Charge set out in the table above. The notice provided to Section D5.2 of Exhibit D will set out, in addition to the requirements of Exhibit D5, a recalculation of the Termination Charge based on the actual costs associated with the Injection Equipment.

EXHIBIT D7 – PRODUCER GAS ACCOUNT BALANCING

D7.1 DIFFERENCE BETWEEN PRODUCED QUANTITY AND MARKET QUANTITY

On a retroactive basis, Company will monitor the difference between the Produced Quantity and the Market Quantity. If the Market Quantity is greater than the Produced Quantity, Company will debit the Producer Gas Account; if the Producer Quantity is greater than the Market Quantity, Company will credit the Producer Gas Account.

D7.2 NOMINATIONS

If Customer does not nominate in a manner that keeps the difference between the Market Quantity and the Produced Quantity to within the range identified in Exhibit D1 (the "PGA Range"), Company may, in addition to its other rights and remedies available under the Agreement or at law, suspend further performance of the Injection Services under this Schedule, and any Upgrading Services under an Upgrading Services Schedule for the Site, if any, or, in the alternative, terminate this Schedule and any Upgrading Services Schedule for the Site.

D7.3 DISPOSITION OF PRODUCER GAS ACCOUNT.

At the end of each Contract Year, disposition of any net debit balance in the Producer Gas Account shall be made as follows:

(a) Customer, by written notice to Company within thirty (30) days of the end of the Contract Year, may elect to provide gas to Company during the one hundred and eighty (180) days following the end of the Contract Year, that portion of any debit balance in the Producer Gas Account as at the end of the Contract Year. Any debit balance in the Producer Gas Account as at the end of the Contract Year which is not both elected to be provided, and actually provided, to Company as aforesaid shall be deemed to have been sold to Customer and Customer shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be:

> 120% of the average price over the Contract Year, based on the published index price for the monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, plus Company's average transportation cost to its franchise area over the Contract Year.

(b) A credit balance in the Producer Gas Account as at the end of the Contract Year must be eliminated in one of the following manners:

(i) By written notice to Company within thirty (30) days of the end of the Contract Year), Customer may direct Company to carry forward a portion of such balance (which portion shall be stipulated in such written notice) as a credit to the Producer Gas Account for the next succeeding Contract Year. Any quantity duly elected to be carried forward under this clause shall, and may only, be reduced in accordance with the following:

A. such quantity must be reduced within the period of one hundred and eighty (180) days ("**Adjustment Period**") immediately following the Contract Year;

B. the Parties will mutually agree on days within the Adjustment Period upon which the Customer may elect to make Nomination(s) of Market Quantity that are less than the lower limit of the Nomination Range set out in Exhibit D1 (each, an "**Adjustment Day**");

C. prior to an Adjustment Day, the Parties will mutually agree on the extent to which Customer's Nomination(s) of Market Quantity may be less than the lower boundary of the Nomination Range.

For certainty, if Customer makes a Nomination of Market Quantity in accordance with Section C above on an Adjustment Day, Customer will not be in breach of Section 6.4 of this Schedule. Subject to the foregoing, the credit balance in the Producer Gas Account shall be deemed to be reduced on each Adjustment Day by the difference between the lower limit of the Nomination Range and the amount nominated on the Adjustment Day (the "**Daily Reduction Volume**").

(ii) Any portion of a credit balance in the Producer Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to Company within thirty (30) days of the end of the Contract Year) to sell under this clause, shall be deemed to have been tendered for sale to Company and Company shall purchase such portion at:

a price per cubic metre of eighty percent (80%) of the average price over the Contract Year for natural gas, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

EXHIBIT D8 – SITE PLAN

[INSTRUCTION: To be completed.]

INJECTION SERVICES SCHEDULE

(Enbridge Not Providing Upgrading Services)

(Site: [●])

THIS INJECTION SERVICES SCHEDULE is entered into as of the ● day of ●, 20___ (the "**Schedule Effective Date**") pursuant to the Biogas Services Agreement made as of [●] between Enbridge Gas Distribution Inc. ("**Company**") and ● ***[INSTRUCTION: Insert full legal name of Customer]*** ("**Customer**"), as amended from time to time (the "**Agreement**"), with respect to the provision of Injection Services pertaining to Customer's Facility at ***[INSTRUCTIONS: insert municipal address]*** (the "**Site**"). Unless otherwise provided below, this Schedule incorporates all of the terms and conditions of the Agreement.

1 INTERPRETATION

1.1 Definitions. All capitalized terms used in this Schedule and not otherwise defined will have the meaning given to them in the Agreement. In this Schedule:

(a) "**Commissioning Date**" means the date when the Injection Equipment at the Site is deemed to have been commissioned into service as determined by Company in its sole discretion and communicated in writing to Customer;

(b) "**Contract Year**" means a 12 month period beginning on the Commissioning Date during the first Contract Year and on the anniversary date of the Commissioning Date for all subsequent Contract Years;

(c) "**Customer's Upgrading Facility**" means the biogas upgrading and conditioning Facility operated by Customer;

(d) "**Day**" shall mean a period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Standard Time. The reference date for any Day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

(e) "**Delivery Point**" means Company's Eastern Delivery Area ("**EDA**"), or Company's Central Delivery Area ("**CDA**") as defined in TransCanada Pipeline Limited's tariff as approved by the National Energy Board, as more specifically set out in Exhibit D1;

(f) "**Eastern Standard Time**" means Eastern Standard Time at Toronto, Ontario; and which, for certainty, includes any adjustment for Daylight Savings Time;

(g) "**Injection Receipt Point**" means the physical point of delivery downstream of Customer's Upgrading Facility to the Injection Equipment; each Injection Receipt Point shall be clearly marked or tagged physically;

(h) "**Market Quantity**" shall mean the daily quantity of Renewable Gas in GJ nominated on that Day by Customer;

(i) "**Nomination**" means a written or electronic request from Customer regarding a quantity of Renewable Gas that Customer intends to deliver to Company

pursuant to this Agreement, or otherwise transfer or assign in a manner contemplated in this Agreement;

(j) "**PGA Range**" has the meaning ascribed thereto in Section **Error! Reference source not found.**;

(k) "**Produced Quantity**" or "**PQ**" is measured in GJ and is the product of:

Produced Volume (10^3m^3) x Producer Heat Value ($GJ/10^3m^3$);

(l) "**Produced Volume**" means the aggregate of all actual volumes of Renewable Gas in 10^3m^3, delivered by Customer to Company at the Injection Receipt Point on any Day;

(m) "**Producer Gas Account**" or "**PGA**" means the producer gas account created by Company to facilitate balancing of the Market Quantity and the Produced Quantity.

(n) "**Producer Heat Value**" means the heat content as set by Company, and shall be determined in accordance with Company's policies and procedures;

(o) "**Schedule**" means this Schedule, including all Exhibits attached to this Schedule and any other documents expressly incorporated by reference herein, as amended from time to time in accordance with this Agreement;

(p) "**Schedule Term**" has the meaning given to it in Section 2.1; and

(q) "**System Capacity**" shall mean the volumetric capacity that exists from time to time within Company's pipeline and distribution system, as determined by Company in its sole discretion.

1.2 Exhibits. The following are the Exhibits to this Schedule as of the Schedule Effective Date:

Exhibit D1	–	Contract Parameters
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Exhibit D5	–	Service Fees
Exhibit D6	–	Termination Charge
Exhibit D7	–	Producer Gas Account Balancing
Exhibit D8	–	Site Plan

2 TERM AND TERMINATION

2.1 Term. The term of this Schedule shall be effective as of the Schedule Effective Date and continue for a term of [***INSTRUCTIONS: insert term.*** ●(●)] years commencing from the Commissioning Date (the "**Schedule Term**), unless terminated earlier in accordance with the Agreement.

2.2 Termination. Subject to the other provisions of this Schedule, this Schedule may be terminated by Company at any time in accordance with Section 6.02 or Section 16.02 of the Agreement.

2.3 Termination Charge. The Termination Charge payable pursuant to this Schedule is specified in Exhibit D6.

2.4 Survival. The provisions of the Agreement identified in Section 16.04 of the main body of the Agreement and incorporated by reference herein and the provisions of this Schedule requiring performance or fulfilment after the expiration or earlier termination of this Agreement, this Section 2.4, such other provisions as are necessary for the interpretation thereof, and any other provisions hereof, the nature and intent of which is to survive termination or expiration of this Agreement, will survive the expiration or earlier termination of this Schedule.

3 CONDITIONS PRECEDENT

The conditions precedent applicable to this Schedule are set out in Exhibit D2.

4 DESCRIPTION OF INJECTION SERVICES

4.1 Provision of Injection Services. Company will provide the Injection Services on the following basis, consistent with the Feasibility Study for the Site:

(a) Company shall be responsible for planning, designing, procuring, installing, constructing, engineering, commissioning, operating and maintaining Equipment of suitable capacity and design as is required for Company to provide the Injection Services in accordance with this Schedule and the Agreement;

(b) Customer shall own, operate and maintain any and all equipment and facilities upstream of the Injection Receipt Point;

(c) the Injection Equipment shall be owned by Company and operated and maintained by Company and/or its contractors or agents;

(d) throughout the Schedule Term, Customer shall provide Renewable Gas to Company at the Injection Receipt Point;

(e) if Biogas provided by Customer fails to conform to the Renewable Gas Specification, Company, in addition to its other remedies, may refuse to accept delivery of the Biogas until such deficiency has been remedied by Customer;

(f) each Party agrees to forthwith notify the other verbally, followed by written notification, if the Biogas provided by Customer at the Injection Receipt Point does not meet the Renewable Gas Specification;

(g) Customer shall deliver, or cause to be delivered, the Produced Volume, up to the Maximum Produced Volume per Day (10^3m^3) during the Schedule Term at the Injection Receipt Point;

(h) Company agrees to accept delivery of the Produced Volume, on a reasonable efforts basis, at the Injection Receipt Point provided that:

(i) Company has sufficient System Capacity to receive the gas offered for delivery by Customer; and

(ii) such gas meets the Renewable Gas Specification;

(i) Company shall deliver at the Delivery Point a Market Quantity provided Customer has tendered its daily quantity Nomination in accordance with Section 5 of this Schedule; and

(j) in the event that there is insufficient System Capacity, Company will not be able to accept the Produced Volume pursuant to this Schedule, and no remedy will be available.

5 NOMINATIONS

(a) Processes. Customer shall use the processes and mechanisms designated from time to time by Company to submit its Nominations for Market Quantity. Customer may provide notice of Nominations as indicated in Exhibit D1. Customer acknowledges that a further corresponding nomination may be required pursuant to any relevant Customer Agreements with Company.

(b) Submittal. Customer shall submit to Company Nominations in accordance with the North American Energy Standards Board ("**NAESB**") standards and at the nomination times (the "**Nomination Times**") set out therein. Valid Nominations must be submitted regularly, failing which the last regular Nomination accepted by Company shall be considered as a standing Nomination applicable to each subsequent Day until varied by Customer.

(c) Acceptance. Acceptance by Company of any Nomination from Customer shall be subject to the other terms and provisions of this Agreement, and is contingent upon the confirmation and actual delivery of the Produced Volume. A Nomination shall only be deemed to be accepted by Company upon issuance of an electronic communication to Customer providing notice of such acceptance.

(d) Revision. Customer shall have the opportunity, subject to acceptance by Company, to revise a Nomination by further notice or notices given to Company, provided that (i) such notice or notices must be given in accordance with the applicable Nomination Times; and (ii) Customer must comply with the other terms and conditions of this Section 5 regarding revisions to the Nomination.

(e) Company Remedies. If Customer does not nominate in accordance with this Section 5, Company may, in addition to its other rights and remedies available under the Agreement or at law, suspend further performance of the Injection Services under this Schedule, or, in the alternative, terminate this Schedule.

6 PRODUCER GAS ACCOUNT BALANCING

6.1 Producer Gas Account. Customer and Company acknowledge that the Producer Heat Value may be greater or less than the energy value associated with Company system gas, and that adjustments will be required to reflect any difference between the Produced Quantity and the Market Quantity. In addition, there may also be differences between the Nominations and the amount produced. To facilitate such adjustments, Company shall establish and maintain on behalf of Customer a Producer Gas Account.

6.2 Producer Gas Account Balancing. Producer Gas Account balancing services will provided in accordance with Exhibit D7. Exhibit D7 may be amended by Company from time to time upon ninety (90) days' notice to Customer.

6.3 Commingling. Company shall have the right to commingle the quantity of Renewable Gas referenced herein with gas owned by Company or gas being stored and/or transported by Company for third parties.

7 EQUIPMENT ON CUSTOMER'S PROPERTY

7.1 Location. The Injection Equipment shall be installed at Customer's premises in the portion of Customer's Site as indicated on the Site Plan attached at Exhibit B8. Customer shall provide such rights in, and access to, Customer's Site and Facility as may be required by Company for the purposes of performing the Services as further set out in Appendix B (Designated Areas) to the Agreement.

7.2 Equipment. The Equipment comprising the Injection Equipment shall be determined by Company in its sole discretion. The Equipment shall generally consist of: a moisture analyzer and gas chromatography, compression, telemetry, metering, odourization and regulator equipment. The Injection Equipment are subject to change in Company's sole discretion, from time to time. Customer agrees that Sections 2.03 and 7.01(4) of, and Appendix B (Designated Areas) to, the Agreement applies in respect of such Equipment.

8 OBLIGATIONS OF CUSTOMER

8.1 Renewable Gas Specification. Throughout the Schedule Term, Customer shall provide Biogas meeting the Renewable Gas Specification to Company at the Injection Receipt Point.

8.2 Cooperation. Customer shall cooperate with Company to facilitate the provision of the Services pursuant to this Schedule including the installation, construction, commissioning, operations and maintenance of the Injection Equipment.

8.3 Customer Acquired Permits and Work. Customer shall obtain Customer Acquired Permits set out in Exhibit D3, and perform the Customer work identified in Exhibit D4, at Customer's own cost and expense.

8.4 Customer Operating Obligations. Customer shall be responsible for the following operating obligations, at its own cost and expense:

(a) a flare located at the Customer's Facility upstream of the Injection Equipment that receives and flares gas from the Injection Equipment, and access to the flare, and Customer will ensure the flare is in good working order and of sufficient capacity to meet the requirements communicated by Company; and

(b) any electrical or other connections reasonably required for the Equipment, including a continuous supply of electrical power at 110 volts.

8.5 Customer's Facility. Customer shall commission and operate the Customer's Facility (including the Customer facility that produces Untreated Biogas and the Customer's Upgrading Facility).

8.6 Maintenance or Shut-Down by Customer. Customer will provide Company with:

(a) an annual schedule of planned preventative maintenance and shutdown activities for the Customer's Facility (including the Customer facility that produces Untreated Biogas and the Customer's Upgrading Facility) by January 31 of each calendar year (and, if the Commissioning Date occurs other than on January 1 of a calendar year, within 30 days of the Commissioning Date);

(b) with respect to any changes to the annual schedule, at least three months' notice of such changes; and

(c) immediately provide notice in the case of an unscheduled shut-down by Customer of the Customer's Facility upstream of the Injection Receipt Point (including the Customer facility that produces Untreated Biogas and the Customer Upgrading Facility).

8.7 Annual Forecast. Customer shall provide to Company not less than sixty (60) days prior to the commencement of each Contract year an annual forecast of the Produced Volume in cubic meters identifying expected daily flows, expected down times and anticipated peak production periods. For certainty, Company shall have no obligation to accept gas from Customer in accordance with any such annual forecast.

8.8 Declaration. Upon request by Company, Customer shall provide to Company a declaration (in a form acceptable to Company) that the Biogas provided at the Injection Receipt Point is derived from biomass for the purposes of GHG reporting pursuant to the *Climate Change Mitigation and Low-carbon Economy Act, 2016*, S.O. 2016, c.7 and regulations.

9 ADDITIONAL OBLIGATIONS OF COMPANY

9.1 Company Acquired Permits. Company shall be responsible for obtaining the Company Acquired Permits set out in Exhibit D3, and performing the Company work identified in Exhibit D4.

9.2 Decommissioning Process. Upon the expiration or termination of this Agreement, Company shall be responsible for safely decommissioning and removing the Injection

Equipment and all of the improvements made pursuant to this Agreement by Company; provided that (i) Company shall have no obligation to remove the permanent civil structures (e.g. the concrete pad) upon which the Equipment is installed, nor to undertake any remedial work [***INSTRUCTIONS: if the Site has unique Decommissioning obligations, please add a "Decommissioning Obligations" Exhibit by including the following language, adding an Exhibit at the end of this document and amending the list of Exhibits in Section 1.2 to include the Decommissioinng Obligations Exhibit: (other than the Decommissioning Obligations itemized in Exhibit ●)]*** to return the Site to its original condition prior to the installation of the Equipment; (ii) gas lines at the Site (including underground gas lines) will be disconnected (in the case of underground gas lines, cut at grade level) and abandoned in place but purged and capped; and (iii) metal structures (such as water pipes and electrical services) will not be removed by Company. All costs associated with Decommissioning will be charged to Customer. Customer shall allow Company a sufficient amount of time to complete the removal of the Injection Equipment and related facilities.

10 CONTROL AND POSSESSION OF BIOGAS

10.1 The Parties agree that:

(a) Customer shall be deemed to be in control and possession of, and responsible for, the Biogas until it shall have been delivered to Company at the Injection Receipt Point and shall bear the full cost and expense for delivering the Biogas to the Injection Receipt Point; and

(b) upon delivery at the Injection Receipt Point and until delivery to the Delivery Point, Company shall be deemed to be in control and possession of, and responsible for, such Biogas..

For certainty, upon delivery to the Delivery Point, Company will be deemed to be in control and possession of, and responsible for, such gas in accordance with the provisions of the relevant Customer Agreements.

11 CURTAILMENT AND SUSPENSION

11.1 In the event of actual or threatened inability to provide the Injection Services under this Schedule by Company due to a Force Majeure Event affecting Company or when curtailment or discontinuance of gas supply is ordered by a Governmental Authority, Customer shall, at the direction of Company, make arrangements to cease deliveries of Renewable Gas and shut down the operation of the Customer's Facility (including the Customer facility that produces Untreated Biogas and the Customer's Upgrading Facility) as needed by Company during the period specified by Company (by notice to Customer in accordance with the other terms of this Agreement). Company shall not be liable, in any event, for any damages, losses, costs or expenses incurred or suffered by Customer by reason of any such curtailment or discontinuance or because of the length of advance notice given directing such curtailment or discontinuance.

11.2 Company may be required from time to time to perform maintenance or construction to its facilities (including the Injection Equipment and Company's gas distribution facilities) which may impact Company's ability to meet Customer's requirements, or Company's

obligations, set out in this Schedule. In such event, except in cases of emergency, Company shall have the right to suspend service under this Agreement in whole or in part; provided that Company and Customer, each acting reasonably, determine a mutually acceptable period during which such maintenance or construction will occur. For certainty, in cases of emergency no prior notice or consultation by Company shall be required to perform any required maintenance or construction, provided Company shall use reasonable efforts to inform Customer of the nature, extent and timing of such emergency. In all cases, Company shall use reasonable efforts to limit the extent and duration of any service interruption hereunder. During any such service interruption, (i) Customer shall shut down the operation of any Customer Facility and systems as needed by Company; and (ii) in cases of emergency, Customer will be required to pay only prorated Service Fees, as determined by Company in its sole discretion, but such prorating shall not affect any other contracts or agreement for services between Company and Customer.

12 REPRESENTATIONS AND WARRANTIES OF CUSTOMER

12.1 In addition to any other representations and warranties given to Company under this Agreement, Customer represents and warrants to Company that at the date hereof and at all times during the Schedule Term:

(a) there are no latent defects at the Premises that will impede Company from obtaining the Company Acquired Permits,

(b) [***INSTRUCTIONS: insert any project-specific reps and warranties that are necessary***]

and acknowledges and agrees that Company is relying on the accuracy of each of such representations and warranties in connection with the entering into of this Agreement and the acceptance by Company of all Renewable Gas from Customer.

13 SERVICES FEES

13.1 Commencing as of ***[INSTRUCTIONS: to confirm - the Commissioning Date]*** and continuing throughout the Schedule Term, Customer shall pay Company the Service Fees set out in Exhibit D5.

13.2 The Service Fees for the first month immediately after the Commissioning Date may be invoiced on a pro-rata basis or deferred until a subsequent month or invoice for the purposes of aligning the Service Fees with the invoice period for the supply of natural gas pursuant to the Customer Account.

13.3 The Service Fees shall be payable in accordance with Section 4.02 of the Agreement.

13.4 If an invoice remains unpaid past the period established in Section 4.02 of the Agreement, Company may, in addition to its other rights and remedies available under the Agreement or at law, suspend further performance of the Injection Services under this Schedule until such invoice is paid or, in the alternative, terminate this Schedule.

[*Remainder of page intentionally left blank*.]

14 GENERAL

14.1 This Schedule may be signed in counterparts, each of which will be deemed to be an original, but all of which taken together, will constitute one and the same instrument. This Schedule may be delivered by electronic transmission, including by email or by facsimile transmission, and if so delivered, this Agreement will be, for all purposes, effective as if the Parties had executed and delivered a manually executed copy of this Agreement. Each Party undertakes to provide the other with a copy of this Agreement bearing original signatures upon request.

IN WITNESS WHEREOF the Parties hereto have executed this Schedule as of the Schedule Effective Date.

ENBRIDGE GAS DISTRIBUTION INC.

● ***[INSTRUCTION: insert full legal name of Customer]***

By: _____

Authorized Signatory

Name: _____

Title: _____

Authorized Signatory

Name: _____

Title: _____

Authorized Signatory

Name: _____

Title: _____

EXHIBIT D1 – CONTRACT PARAMETERS

The following table sets out the contract parameters and notice requirements for Nominations:

Contract Parameter	Details
Site	[●municipal address]
Delivery Point	The gas production site measured by Company's meter located at [Lot___, Concession___, _____Township, _____ County, Province of Ontario, Station #_____]
Producer Heat Value	The deemed Producer Heat Value as of the Commissioning Date is: [●]
Maximum Produced Volume per Day	[●] 10^3m^3
Allowable Operating Pressure	Minimum: [●] kPa Maximum: [●] kPa The pressure of the Biogas delivered by Customer to Company at the Injection Receipt Point shall be sufficient to move gas into Company's pipeline, and shall be at least the minimum specified above but shall not exceed the maximum limit specified above. Company may change the allowable operating pressure from time to time and Company shall provide to Customer six (6) months' notice of such change.
PGA Range	[●]
Notice for Nominations	gascontrol@enbridge.com

EXHIBIT D2 – CONDITIONS PRECEDENT

D2.1 The obligations of Company to provide the Services pursuant to this Schedule are subject to the following conditions precedent:

(a) Company shall have obtained, in form and substance satisfactory to Company, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders, and authorizations that are required to:

(i) construct and operate the Equipment; and

(ii) provide the Services,

under a regulatory framework satisfactory to Company, in its sole discretion; and

(b) each of the Parties shall have received all Required Orders for the construction and operation of the Customer's Facility and the Equipment at the Site

D2.2 The obligations of Company to provide the Services pursuant to this Schedule are subject to the following conditions precedent, which are for the sole benefit of Company and which may be waived in whole or in part by Company:

(a) Company shall have completed and placed into service the facilities and equipment necessary to provide the Services hereunder;

(b) Company, where applicable, shall have received from Customer executed Customer Agreements; and

(c) Customer shall have provided Company with notice that Customer has: (i) obtained all Customer Acquired Permits pertaining to the Services, and (ii) the Customer's Facility (including the Customer facility that produces Untreated Biogas and the Customer's Upgrading Facility) and related infrastructure is commissioned.

EXHIBIT D3 – REQUIRED ORDERS

[INSTRUCTION: To be completed.]

EXHIBIT D4 – CONSTRUCTION PHASE: COMPANY AND CUSTOMER WORK

[INSTRUCTION: To be completed.]

EXHIBIT D5 – SERVICE FEES

Customer shall pay to Company the following Service Fees in respect of the Services provided by Company to Customer pursuant to this Schedule.

Customer will pay a Service Fee on a monthly basis (the "**Monthly Service Fee**"), determined in accordance with the following:

D5.1 INITIAL MONTHLY SERVICE FEE

The following fee (the "**Initial Monthly Service Fee**") will be invoiced to Customer from and after the Commissioning Date. The Initial Monthly Service Fee is based on Company's initial estimates of the capital, operating and financing cost requirements (and applicable taxes) of the Injection Equipment:

Initial Monthly Service Fee: $[●], plus applicable taxes

D5.2 DETERMINATION OF MONTHLY SERVICE FEE AND TRUE-UP OF INITIAL MONTHLY SERVICE FEE

(a) As of and from the Commissioning Date until the Monthly Service Fee is settled in accordance with this Section D5.2, Customer will pay the Initial Monthly Service Fee as set out above.

(b) Within twenty (20) Business Days of the 6 month anniversary of the Commissioning Date, Company will prepare and deliver to Customer a notice setting out the Monthly Service Fees, recalculated on the basis of the actual costs incurred by Company, and the Monthly Service Fee for the remainder of the Term will be invoiced in accordance with the Monthly Service Fee set out in the notice (subject to amendment in accordance with the Agreement and this Schedule).

(c) If the Monthly Service Fee in the notice exceeds the Initial Monthly Service Fee, Company will, within two (2) billing cycles of such determination, debit the monthly invoice issued by Company to Customer for the Services for an amount equal to such difference multiplied by the number of billing cycles in respect of which Customer was charged the Initial Monthly Service Fee. If the Monthly Service Fee as so determined is less than the Initial Monthly Service Fee, Company will, within two (2) billing cycles of such determination, credit the monthly invoice issued by Company to Customer for the Services for an amount equal to such difference multiplied by the number of billing cycles in respect of which Customer was charged the Initial Monthly Service Fee.

EXHIBIT D6 - TERMINATION CHARGE

D6.1 TERMINATION CHARGE PRIOR TO COMMISSIONING DATE

For purposes of calculating the Termination Charge in the event of a termination prior to the Commissioning Date, the Termination Charge will be calculated by Company based upon the aggregate of all internal and external costs, expenses and overheads incurred by Company up to, and resulting from, the termination, including but not limited to those relating to: site and station design and studies, permitting fees, site preparation, construction, material, equipment, third party parts and components, maintenance, decommissioning, site and station restoration and associated cancellation fees up to an amount that will not exceed the Termination Charge for Contract Year 1 as set out in the table below.

D6.2 TERMINATION CHARGE AS OF AND FROM THE COMMISSIONING DATE

Contract Year during which Termination Occurs*	Termination Charge
1	[●]
2	[●]
3	[●]
4	[●]
5	[●]
6	[●]
7	[●]
8	[●]
9	[●]
10	[●]

* For greater certainty, the Termination Charge will decrease each Contract Year following the first Contract Year as shown in the above table.

D6.3 DETERMINATION OF TERMINATION CHARGE

As of and from the Commissioning Date until the Monthly Service Fee is settled in accordance with Exhibit D5, the Termination Charge will be the Termination Charge set out in the table above. The notice provided to Section D5.2 of Exhibit D will set out, in addition to the requirements of Exhibit D5, a recalculation of the Termination Charge based on the actual costs associated with the Injection Equipment.

EXHIBIT D7 – PRODUCER GAS ACCOUNT BALANCING

D7.1 DIFFERENCE BETWEEN PRODUCED QUANTITY AND MARKET QUANTITY

On a retroactive basis, Company will monitor the difference between the Produced Quantity and the Market Quantity. If the Market Quantity is greater than the Produced Quantity, Company will debit the Producer Gas Account; if the Producer Quantity is greater than the Market Quantity, Company will credit the Producer Gas Account.

D7.2 NOMINATIONS

If Customer does not nominate in a manner that keeps the difference between the Market Quantity and the Produced Quantity to within the range identified in Exhibit D1 (the "PGA Range"), Company may, in addition to its other rights and remedies available under the Agreement or at law, suspend further performance of the Injection Services under this Schedule, or, in the alternative, terminate this Schedule.

D7.3 DISPOSITION OF PRODUCER GAS ACCOUNT.

At the end of each Contract Year, disposition of any net debit balance in the Producer Gas Account shall be made as follows:

(a) Customer, by written notice to Company within thirty (30) days of the end of the Contract Year, may elect to provide gas to Company during the one hundred and eighty (180) days following the end of the Contract Year, that portion of any debit balance in the Producer Gas Account as at the end of the Contract Year. Any debit balance in the Producer Gas Account as at the end of the Contract Year which is not both elected to be provided, and actually provided, to Company as aforesaid shall be deemed to have been sold to Customer and Customer shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be:

> 120% of the average price over the Contract Year, based on the published index price for the monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, plus Company's average transportation cost to its franchise area over the Contract Year.

(b) A credit balance in the Producer Gas Account as at the end of the Contract Year must be eliminated in one of the following manners:

(i) By written notice to Company within thirty (30) days of the end of the Contract Year), Customer may direct Company to carry forward a portion of such balance (which portion shall be stipulated in such written notice) as a credit to the Producer Gas Account for the next succeeding Contract Year. Any quantity duly elected to be carried forward under this clause shall, and may only, be reduced in accordance with the following:

A. such quantity must be reduced within the period of one hundred and eighty (180) days ("**Adjustment Period**") immediately following the Contract Year;

B. the Parties will mutually agree on days within the Adjustment Period upon which the Customer may elect to make Nomination(s) of Market Quantity that are less than the lower limit of the Nomination Range set out in Exhibit D1 (each, an "**Adjustment Day**");

C. prior to an Adjustment Day, the Parties will mutually agree on the extent to which Customer's Nomination(s) of Market Quantity may be less than the lower boundary of the Nomination Range.

For certainty, if Customer makes a Nomination of Market Quantity in accordance with Section C above on an Adjustment Day, Customer will not be in breach of Section 6.4 of this Schedule. Subject to the foregoing, the credit balance in the Producer Gas Account shall be deemed to be reduced on each Adjustment Day by the difference between the lower limit of the Nomination Range and the amount nominated on the Adjustment Day (the "**Daily Reduction Volume**").

(ii) Any portion of a credit balance in the Producer Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to Company within thirty (30) days of the end of the Contract Year) to sell under this clause, shall be deemed to have been tendered for sale to Company and Company shall purchase such portion at:

a price per cubic metre of eighty percent (80%) of the average price over the Contract Year for natural gas, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

EXHIBIT D8 – SITE PLAN

[INSTRUCTION: To be completed.]

APPENDIX E
to the Biogas Services Agreement between
Enbridge Gas Distribution Inc. and
● *[INSTRUCTION: Insert full legal name of Customer]*
dated ●

FORM OF UPGRADING SERVICES SCHEDULE

[Please see attached.]

UPGRADING SERVICES SCHEDULE
(Site: [●])

THIS BIOGAS UPGRADING SERVICES SCHEDULE is entered into as of the ● day of ●, 20___ (the "**Schedule Effective Date**") pursuant to the Biogas Services Agreement made as of [●] between Enbridge Gas Distribution Inc. ("**Company**") and ● ***[INSTRUCTION: Insert full legal name of Customer]*** ("**Customer**"), as amended from time to time (the "**Agreement**"), with respect to the provision of Upgrading Services pertaining to Customer's Facility at ***[INSTRUCTIONS: insert municipal address]*** (the "**Site**"). Unless otherwise provided below, this Schedule incorporates all of the terms and conditions of the Agreement.

1 INTERPRETATION

1.1 Definitions. All capitalized terms used in this Schedule and not otherwise defined will have the meaning given to them in the Agreement. In this Schedule:

(a) "**Commissioning Date**" means the date when the ***[INSTRUCTION: confirm the Upgrading Equipment and the Injection Equipment will have the same Commissioning Date at this specific site.]*** Upgrading Equipment at the Site are deemed to have been commissioned into service as determined by Company in its sole discretion and communicated in writing to Customer;

(b) "**Contract Year**" means a 12 month period beginning on the Commissioning Date during the first Contract Year and on the anniversary date of the Commissioning Date for all subsequent Contract Years;

(c) "**Schedule**" means this Schedule, including all Exhibits attached to this Schedule and any other documents expressly incorporated by reference herein, as amended from time to time in accordance with this Agreement;

(d) "**Schedule Term**" has the meaning given to it in Section 2.1;

(e) "**Untreated Biogas Specification**" means the specification for the Untreated Biogas as set forth in Exhibit E2 herein;

(f) "**Upgrading Equipment Area**" means the area in which the Equipment will be installed by Company,[being the cross-hatched area that is identified as the Upgrading Equipment Area in Exhibit [●] to the Injection Services Schedule for the Site];

(g) "**Upgrading Receipt Point**" means the physical point of delivery to Company upstream of the Upgrading Equipment; each Upgrading Receipt Point shall be clearly marked or tagged physically;

1.2 Exhibits. The following are the Exhibits to this Schedule as of the Schedule Effective Date:

Exhibit E1	–	Conditions Precedent
Exhibit E2	–	Feasibility Study

Exhibit E3	–	Required Orders
Exhibit E4	–	Construction Phase: Company and Customer Work
Exhibit E5	–	Customer Operating Obligations
Exhibit E6	–	Performance Requirements
Exhibit E7	–	Service Fees
Exhibit E8	–	Termination Charge

2 TERM AND TERMINATION

2.1 Term. The term of this Schedule shall be effective as of the Schedule Effective Date and continue for a term of [***INSTRUCTIONS: insert term.*** ●(●)] years commencing from the Commissioning Date (the "**Schedule Term**"), unless terminated earlier in accordance with the Agreement.

2.2 Termination. Subject to the other provisions of this Schedule, this Schedule may be terminated by Company at any time in accordance with Section 6.02 or Section 16.02 of the Agreement.

2.3 Termination Charge. The Termination Charge payable pursuant to this Schedule, in accordance with Section 16.03(2) of the Agreement, is set out at Exhibit E8.

2.4 Survival. The provisions of the Agreement identified in Section 16.04 of the main body of the Agreement and incorporated by reference herein and the provisions of this Schedule requiring performance or fulfilment after the expiration or earlier termination of this Agreement, this Section 2.4, such other provisions as are necessary for the interpretation thereof, and any other provisions hereof, the nature and intent of which is to survive termination or expiration of this Agreement, will survive the expiration or earlier termination of this Schedule.

3 CONDITIONS PRECEDENT

The conditions precedent applicable to this Schedule are set out in Exhibit E1.

4 DESCRIPTION OF UPGRADING SERVICES

4.1 Provision of Upgrading Services. Company will provide Upgrading Services to condition and upgrade Untreated Biogas meeting the Untreated Biogas Specification on the following basis, consistent with the Feasibility Study:

(a) Company will be responsible for planning, designing, procuring, installing, constructing, engineering, commissioning, operating and maintaining Equipment of suitable capacity and design as is required for Company to provide the Upgrading Services in accordance with this Schedule and the Agreement;

(b) Customer shall own, operate and maintain any and all equipment and facilities upstream of the Upgrading Receipt Point;

(c) the Upgrading Equipment shall be owned by Company and operated and maintained by Company and/or its contractors or agents;

(d) throughout the Schedule Term, Customer shall provide Company with Untreated Biogas that meets the Untreated Biogas Specification at the Upgrading Receipt Point;

(e) if the Untreated Biogas provided by Customer fails to conform to the Untreated Biogas Specification, Company, in addition to its other remedies, may refuse to accept delivery of the Untreated Biogas until such deficiency has been remedied by Customer; and

(f) each Party agrees to forthwith notify the other verbally, followed by written notification, if the Untreated Biogas provided by Customer at the Upgrading Receipt Point does not meet the Untreated Biogas Specification.

4.2 Outline. The Upgrading Services will be performed by Company as follows:

(a) Construction:

(i) Company will complete the construction of the Upgrading Equipment in accordance with the Feasibility Study and in accordance with the following:

A. [●]

(ii) Customer and Company will each perform the work allocated to each of them set out in Exhibit E4.

(iii) Subject to the fulfilment of the conditions precedent, in each case to the satisfaction of Company in its sole discretion, Company will supply and install the Equipment.

(b) Commissioning:

(i) Upon completion of its installation of the Upgrading Equipment at the Site, Company shall conduct or arrange for qualified third parties to conduct, appropriate tests and inspections, in order to (i) confirm delivery from the Upgrading Equipment of Renewable Gas produced from the Untreated Biogas, (ii) confirm that the Performance Requirements have been met, or have been deemed to have been met at Company's discretion, and (iii) to verify that the installed Equipment is fully functional and may be operated safely. Customer shall permit Company, its authorized subcontractors, and inspectors or other officials from the TSSA, the ESA and other governmental or regulatory authorities, to access and enter the Site for the foregoing purposes.

(ii) As required, Company will obtain the Company Acquired Permits identified in Exhibit E3 in connection with commissioning and operation of the Upgrading Equipment.

(iii) Upon completion of the steps outlined above (the "**Commissioning**"), Company will provide notice to Customer that the Upgrading Equipment have been commissioned, and the Upgrading Equipment shall be deemed to have been commissioned into service.

(c) Operation:

(i) As of the Commissioning Date, Company will commence operations of the Upgrading Equipment and performance of all maintenance for the Upgrading Equipment consistent with the manufacturer's recommendations. The Upgrading Equipment operation and maintenance activities include, but are not limited to, the following: preventative maintenance, corrective maintenance, spare parts and consumables inventory tracking, on-call support, media change-out and disposal, process control, and data monitoring, collection, storage and reporting.

(ii) Save and except as specifically provided in the Performance Requirements, Company makes no representations, warranties or guarantees concerning the quantity or quality of Renewable Gas that can or will be produced by the Upgrading Equipment, nor shall Company have any obligation to produce a pre-determined minimum level of Renewable Gas.

5 EQUIPMENT ON CUSTOMER'S PROPERTY

5.1 Location. The Upgrading Equipment shall be installed at Customer's premises[, and the location shall be within the portion of the Designated Areas identified as the "Upgrading Equipment Area" in Exhibit D8 to the Injection Services Schedule for the Site]. Customer shall provide such rights in, and access to, Customer's Site and Facilities as may be required by Company for the purposes of performing the Services as further set out in Appendix B (Designated Areas) to the Agreement.

5.2 Equipment. The Equipment comprising the Upgrading Equipment shall be determined by Company in its sole discretion. The Upgrading Equipment is subject to change in Company's sole discretion, from time to time. Customer agrees that Sections 2.03 and 7.01(4) of, and Appendix B (Designated Areas) to, the Agreement applies in respect of such Equipment.

6 OBLIGATIONS OF CUSTOMER

6.1 Untreated Biogas Delivery. As a condition of the obligation of Company to achieve the Performance Requirements, Customer shall provide Untreated Biogas to Company at the Upgrading Receipt Point that meets the Untreated Biogas Specification.

6.2 Customer Acquired Permits and Customer Work. Customer shall be responsible for obtaining the Customer Acquired Permits set out in Exhibit E3 and performing the Customer work described in Exhibit E4.

6.3 Customer Operating Obligations. Customer shall be responsible for the operating obligations set out in Exhibit E5.

6.4 Annual Forecast. Customer shall provide to Company not less than sixty (60) days prior to the commencement of each Contract year an annual forecast of the Untreated Biogas volumes in cubic meters identifying expected daily flows, expected down times and anticipated peak production periods. For certainty, Company will have no obligation to accept gas from Customer in accordance with any such annual forecast.

6.5 Maintenance or Shut-Down by Customer. Customer will provide Company with:

(a) an annual schedule of planned preventative maintenance and shutdown activities for the Customer's Facilities by January 31 of each calendar year (and, if the Commissioning Date is other than on January 1 of a calendar year, within 30 days of the Commissioning Date);

(b) with respect to any changes to the annual schedule, at least three months' notice of such changes; and

(c) immediately provide notice in the case of an unscheduled shut-down by Customer of the Customer's Facilities that produce Untreated Biogas.

7 ADDITIONAL OBLIGATIONS OF COMPANY

7.1 Company Acquired Permits. Company shall be responsible for obtaining the Company Acquired Permits set out in Exhibit E3, and performing the Company work identified in Exhibit E4.

7.2 Performance Requirements. Company will operate the Upgrading Equipment so that as of the Commissioning Date, and subject to Customer's obligation to provide Untreated Biogas meeting the Untreated Biogas Specification, the Upgrading Equipment shall satisfy the Performance Requirements set forth in Exhibit E6.

7.3 Decommissioning Process. Upon the expiration or termination of this Agreement, Company will be responsible for safely decommissioning and removing the Upgrading Equipment and all of the improvements made pursuant to this Agreement by the Company; provided that (i) Company will have no obligation to remove the permanent civil structures (e.g. the concrete pad) upon which the Equipment is installed, nor to undertake any remedial work [***INSTRUCTIONS: if the Site has unique Decommissioning obligations, please add a "Decommissioning Obligations" Exhibit by including the following language, adding an Exhibit at the end of this document and amending the list of Exhibits in Section*** *Error! Reference source not found.* ***to include the Decommissioinng Obligations Exhibit: (other than the Decommissioning Obligations itemized in Exhibit ●)]*** to return the Site to its original condition prior to the installation of the Equipment; (ii) gas lines at the Site (including underground gas lines) will be disconnected (in the case of underground gas lines, cut at grade level) and abandoned in place but purged and capped; and (iii) metal structures (such as water pipes and electrical services) will not be removed by Company. All costs associated with Decommissioning will be charged to Customer. Customer will allow Company a sufficient amount of time to complete the removal of the Upgrading Equipment and related facilities.

8 CONTROL AND POSSESSION OF BIOGAS

8.1 The Parties agree that:

(a) Customer shall be deemed to be in control and possession of, and responsible for, the Biogas until it shall have been delivered to Company at the Upgrading Receipt Point, and shall bear the full cost and expense for delivering the Biogas to the Upgrading Receipt Point; and

(b) upon delivery at the Upgrading Receipt Point and until delivery to the Delivery Point (as defined in the Injection Services Schedule for the Site), Company shall be deemed to be in control and possession of, and responsible for, such Biogas.

9 CURTAILMENT AND SUSPENSION

9.1 In the event of actual or threatened inability to provide the Services under this Schedule by Company due to a Force Majeure Event affecting Company or when curtailment or discontinuance of gas supply is ordered by a Governmental Authority, Customer shall, at the direction of Company, make arrangements to cease deliveries of Untreated Biogas and shut down the operation of Customer Facilities as needed by Company during the period specified by Company (by notice to Customer in accordance with the other terms of the Agreement). Company shall not be liable, in any event, for any damages, losses, costs or expenses incurred or suffered by Customer by reason of any such curtailment or discontinuance or because of the length of advance notice given directing such curtailment or discontinuance.

9.2 Company may be required from time to time to perform maintenance or construction to its facilities (including the Upgrading Equipment, the Injection Facilities and the gas distribution facilities) which may impact Company's ability to meet Customer's requirements, or Company's obligations, set out in this Schedule. In such event, except in cases of emergency, Company shall have the right to suspend service under this Schedule in whole or in part; provided that Company and Customer, each acting reasonably, determine a mutually acceptable period during which such maintenance or construction will occur. In cases of emergency no prior notice or consultation by Company shall be required to perform any required maintenance or construction, provided Company shall use reasonable efforts to inform Customer of the nature, extent and timing of such emergency. In all cases, Company shall use reasonable efforts to limit the extent and duration of any service interruption hereunder. During any such service interruption, (i) Customer shall make arrangements to stop deliveries of Untreated Biogas and shut down the operation of any Customer systems as needed by Company; and (ii) in cases of emergency, Customer will be required to pay only prorated Service Fees, as determined by Company in its sole discretion, but such prorating shall not affect any other contracts or agreement for services between Company and Customer.

10 REPRESENTATIONS AND WARRANTIES OF CUSTOMER

10.1 In addition to any other representations and warranties given to Company under this Agreement, Customer represents and warrants to Company that at the date hereof and at all times during the Schedule Term:

(a) there are no Latent Defects at the Premises that will impede Company from obtaining the Company Acquired Permits;

(b) [***INSTRUCTIONS: insert any project-specific reps and warranties that are necessary***]

and acknowledges and agrees that Company is relying on the accuracy of each of such representations and warranties in connection with the entering into of this Agreement and the acceptance by Company of all Untreated Biogas from Customer.

11 SERVICE FEES

11.1 Commencing as of ***[INSTRUCTIONS: to confirm - the Commissioning Date]*** and continuing throughout the Schedule Term of this Schedule, Customer shall pay Company the Service Fees set out in Exhibit E7.

11.2 The Service Fees for the first month immediately after the Commissioning Date may be invoiced on a pro-rata basis or deferred until a subsequent month or invoice for the purposes of aligning the Service Fees with the invoice period for the supply of natural gas pursuant to the Customer Account.

11.3 The Service Fees shall be payable in accordance with Section 4.02 of the Agreement.

11.4 If an invoice remains unpaid past the period established in Section 4.02 of the Agreement, Company may, in addition to its other rights and remedies available under the Agreement or at law, suspend further performance of the Upgrading Services under this Schedule until such invoice is paid or, in the alternative, terminate this Schedule.

[*Remainder of page intentionally left blank*.]

12 GENERAL

12.1 This Schedule may be signed in counterparts, each of which will be deemed to be an original, but all of which taken together, will constitute one and the same instrument. This Schedule may be delivered by electronic transmission, including by email or by facsimile transmission, and if so delivered, this Agreement will be, for all purposes, effective as if the Parties had executed and delivered a manually executed copy of this Agreement. Each Party undertakes to provide the other with a copy of this Agreement bearing original signatures upon request.

IN WITNESS WHEREOF the Parties hereto have executed this Schedule as of the Schedule Effective Date.

ENBRIDGE GAS DISTRIBUTION INC.

● *[INSTRUCTION: insert full legal name of Customer]*

By: _____
Authorized Signatory

Name: _____

Title: _____

By: _____
Authorized Signatory

Name: _____

Title: _____

EXHIBIT E1 – CONDITIONS PRECEDENT

E1.1 The obligations of Company to provide the Services pursuant to this Schedule are subject to the following conditions precedent:

(a) Company shall have obtained, in form and substance satisfactory to Company, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders, and authorizations that are required to:

(i) construct and operate the Equipment; and

(ii) provide the Services,

under a regulatory framework satisfactory to Company, in its sole discretion; and

(b) each of the Parties shall have received all Required Orders for the construction and operation of the Customer's Facility and the Equipment at the Site

E1.2 The obligations of Company to provide the Services pursuant to this Schedule are subject to the following conditions precedent, which are for the sole benefit of Company and which may be waived in whole or in part by Company:

(a) Company shall have completed and placed into service the facilities and equipment necessary to provide the Services hereunder;

(b) Company, where applicable, shall have received from Customer executed Customer Agreements; and

(c) Customer shall have provided Company with notice that Customer has: (i) obtained all Customer Acquired Permits pertaining to the Services, and (ii) the Customer's Facility (including the Customer facility that produces Untreated Biogas and the Customer's Upgrading Facility) and related infrastructure is commissioned.

EXHIBIT E2 – FEASIBILITY STUDY

[INSTRUCTION: To be completed.]

EXHIBIT E3 – REQUIRED ORDERS

[INSTRUCTION: To be completed.]

EXHIBIT E4 - CONSTRUCTION PHASE: COMPANY AND CUSTOMER WORK

[INSTRUCTION: To be completed.]

EXHIBIT E5 – CUSTOMER OPERATING OBLIGATIONS

[INSTRUCTION: To be completed.]

EXHIBIT E6 - PERFORMANCE REQUIREMENTS

[INSTRUCTION: To be completed.]

EXHIBIT E7 – SERVICE FEES

Customer shall pay to Company the following Service Fees in respect of the Services provided by Company to Customer pursuant to this Schedule.

Customer will pay a Service Fee on a monthly basis (the "**Monthly Service Fee**") determined in accordance with the following:

E7.1 INITIAL MONTHLY SERVICE FEE

The following fee (the "**Initial Monthly Service Fee**") will be invoiced to Customer from and after the Commissioning Date. The Initial Monthly Service Fee is based on Company's initial estimates of the capital, operating and financing cost requirements (and applicable taxes) of the Upgrading Equipment:

Initial Monthly Service Fee: $[●], plus applicable taxes

E7.2 DETERMINATION OF MONTHLY SERVICE FEE AND TRUE-UP OF INITIAL MONTHLY SERVICE FEE

(a) As of and from the Commissioning Date until the Monthly Service Fee is settled in accordance with this Section E7.2, Customer will pay the Initial Monthly Service Fee as set out above.

(b) Within twenty (20) Business Days of the 6 month anniversary of the Commissioning Date, Company will prepare and deliver to Customer a notice setting out the Monthly Service Fee, recalculated on the basis of the actual costs incurred by Company, and the Monthly Service Fee for the remainder of the Term will be invoiced in accordance with the Monthly Service Fee set out in the notice (subject to amendment in accordance with the Agreement and this Schedule).

(c) If the Monthly Service Fee in the notice exceeds the Initial Monthly Service Fee, Company will, within two (2) billing cycles of such determination, debit the monthly invoice issued by Company to Customer for the Services for an amount equal to such difference multiplied by the number of billing cycles in respect of which Customer was charged the Initial Monthly Service Fee. If the Monthly Service Fee is less than the Initial Monthly Service Fee, Company will, within two (2) billing cycles of such determination, credit the monthly invoice issued by Company to Customer for the Services for an amount equal to such difference multiplied by the number of billing cycles in respect of which Customer was charged the Initial Monthly Service Fee.

E7.3 ADJUSTMENT OF MONTHLY SERVICE FEE TO REFLECT CHANGES IN FEES PAYABLE BY COMPANY TO OPERATOR OF THE UPGRADING EQUIPMENT

The Parties acknowledge and agree that to a significant extent the operating costs included in the calculation of the Monthly Service Fee will be an amount comprised of the total fees payable by Company to the operator engaged by Company to operate the Upgrading Equipment

pursuant to the then current management agreement (the "**Management Agreement**") between Company and the operator. The Initial Monthly Service Fee incorporates an estimate of the fees to be payable under the Management Agreement. The fees payable under the initial Management Agreement will be incorporated into the Monthly Service Fee determined in accordance with Section E7.2 above. The Parties acknowledge and agree that in the event that the then current Management Agreement expires or terminates and Company enters into a replacement Management Agreement, the Monthly Service Fee will be adjusted to reflect any increase or decrease, as applicable, in the fees payable by Company pursuant to the Management Agreement.

EXHBIT E8 - TERMINATION CHARGE

E8.1 TERMINATION CHARGE PRIOR TO COMMISSIONING DATE

For purposes of calculating the Termination Charge in the event of a termination prior to the Commissioning Date, the Termination Charge will be calculated by Company based upon the aggregate of all internal and external costs, expenses and overheads incurred by Company up to, and resulting from, the termination, including but not limited to those relating to: site and station design and studies, permitting fees, site preparation, construction, material, equipment, third party parts and components, maintenance, decommissioning, site and station restoration and associated cancellation fees up to an amount that will not exceed the Termination Charge for Contract Year 1 as set out in the table below.

E8.2 TERMINATION CHARGE AS OF AND FROM THE COMMISSIONING DATE

Contract Year during which Termination Occurs*	**Termination Charge**
1	[●]
2	[●]
3	[●]
4	[●]
5	[●]
6	[●]
7	[●]
8	[●]
9	[●]
10	[●]

* For greater certainty, the Termination Charge will decrease each Contract Year following the first Contract Year as shown in the above table.

E8.3 DETERMINATION OF TERMINATION CHARGE

As of and from the Commissioning Date until the Monthly Service Fee is settled in accordance with Exhibit E7, the Termination Charge will be the Termination Charge set out in the Table above. The notice provided to Section E7.2 of Exhibit E7 will set out, in addition to the requirements of Exhibit E7, a recalculation of the Termination Charge based on the actual costs associated with the Upgrading Equipment.

APPENDIX F
to the Biogas Services Agreement between
Enbridge Gas Distribution Inc. and
● *[INSTRUCTION: Insert full legal name of Customer]*
dated ●

FINANCIAL ASSURANCES

[INSTRUCTION: To be completed.]

STAFF INTERROGATORY #7

INTERROGATORY

Issue 2 – Cost Consequences

Topic: RNG Enabling Program

Ref: Exhibit B / Tab 1 / Schedule 1 / p. 12, #38 and p. 14, #43
Exhibit B / Tab 1 / Schedule 1 / p. 17, #50

Preamble:
Enbridge Gas outlines the potential for RNG in Ontario and Canada based on the ICF Report. Enbridge Gas indicates that its primary focus has been on municipalities (which are listed).

Enbridge Gas states that all RNG producers requesting to inject RNG into its distribution system will be required to contract for the Injection Service, including RNG producers who do not require Upgrading Service.

Questions:

a) What is Enbridge Gas' role in these discussions with the municipalities? Please explain.
   i) Are these municipalities (e.g., City of Toronto, Region of Peel, Durham Region, Niagara Region and the City of Peterborough) considered to be RNG suppliers/producers?

b) Has Enbridge Gas entered into any agreements with the municipalities (e.g., any tax breaks, etc.)? Please explain.

c) Please explain whether the municipalities (City of Toronto, Region of Peel, Durham Region, Niagara Region and the City of Peterborough) where Enbridge Gas participated in RNG discussions are within Enbridge Gas' current service territory?
   i) Please explain whether Enbridge Gas will enter into discussions with municipalities that are outside of its current service territory (e.g., in Union Gas' current service territory)? If so, has Enbridge Gas entered into an agreement with Union Gas?
   ii) Does Enbridge Gas intend to enter into discussions in relation to its RNG Enabling Program with RNG suppliers that produce RNG from farms, forests, etc.? Please explain.

d) Has Enbridge Gas conducted any surveys in the marketplace for its proposed RNG Enabling Program – Upgrading Services? If so, please file the results.
   i) How many customers has Enbridge Gas estimated to purchase its RNG Upgrading Service for years 1 to 10? Please explain and provide all documentation including data, analysis and assumptions.
      1. What is this share (number of customers purchasing Enbridge Gas' Upgrading Service) in terms of the Ontario Resource Potential Estimate of 627 m3/y for years 1 to 10?

e) Has Enbridge Gas conducted any surveys in the marketplace for its proposed RNG Enabling Program – Injection Services? If so, please file the results.
   i) How many customers has Enbridge Gas estimated to purchase its RNG Injection Service for years 1 to 10? Please explain and provide all documentation including data, analysis and assumptions.
      1. What is this share (number of customers purchasing Enbridge Gas' Injection Service) in terms of the Ontario Resource Potential Estimate of 627 m3/y?

RESPONSE

a) Given that municipalities are typically responsible for the collection and disposal of garbage and collection and treatment of waste water they are seen as one of the province's major sources of biomass which is required in order to produce RNG. Enbridge communicates with representatives of municipalities to point out the potential value of RNG as a GHG abatement tool and discusses how the Company can work with these entities to bring potential RNG production to fruition.
   i) Yes. The listed municipalities are considered to be potential sources of RNG.

b) Yes, Enbridge has entered into an agreement with the City of Toronto to provide RNG upgrading and injection services for one of the City's waste collection and sorting facilities. The RNG Enabling programs and the Geothermal Energy Service do not require municipal tax relief as part of their respective financing mechanisms.

c) Enbridge currently provides gas distribution services in the City of Toronto, Region of Peel, Durham Region, Niagara Region and the City of Peterborough.
   i) Enbridge has not entered into discussions with municipalities that are outside of its current service territory. Enbridge has not entered into an agreement with Union Gas with respect to the provision of RNG enabling services at sites located in Union Gas' service area.

ii) Yes. The Company views all of these types of operations as potential sources of RNG and has and will continue to discuss the potential for RNG production with the operators of these types of facilities and how the Company can work with these entities to bring potential RNG production online.

d) While Enbridge has not conducted surveys, it has been informed by discussions with potential biogas producers. The ultimate take up of its services will depend on several factors, including whether a utility RNG procurement process is launched, demand for RNG from direct purchase customers and potential ex-franchise users of RNG as well as the specific feasibility of connecting sites to the Company's gas distribution system. It is the Company's assessment that up to 37 RNG production facilities could be operating by 2025. The Company has not completed a detailed estimate as to what extent those production facilities would avail themselves of the RNG Upgrading Service.
    i) Please see the response to d) above.
        1. Please see the response to d) above.

e) Please see the response to part d) above.

STAFF INTERROGATORY #8

INTERROGATORY

Issue 2 – Cost Consequences

Topic: RNG Enabling Program

Ref: Exhibit B / Tab 1 / Schedule 1 / p. 17, #49, p. 18 #53 and p.57, #57, Table 1

Preamble:
Enbridge Gas states that its Upgrading Service will be offered to potential RNG producers as an optional service. Producers choosing this option will contract with Enbridge Gas to plan, design, procure, construct, own, operate and maintain biogas conditioning and upgrading equipment on the producer's premises.

Enbridge Gas also states that it will ensure that the RNG injected into the gas distribution system, at a minimum, meets the requirements of CSA Z662 and other applicable codes and standards as specified in its policies.

Questions:

a) Please explain how Enbridge Gas developed its expertise in planning, designing, operating and maintaining biogas conditioning and upgrading equipment?
   i) Is this internal expertise? Please explain.
      1. If so, how many FTEs were trained and what were the costs for training, etc.?
      2. If not, what are costs and resources to hire external expertise? Please explain.

b) Please explain the circumstances where Enbridge Gas would exceed the requirements of CSA Z662 and other applicable codes and standards as specified in its policies for RNG injected into its gas distribution system.

RESPONSE

a) i) The conditioning of RNG is an extension of Enbridge's existing knowledge on natural gas as the primary component in biogas gas is methane, which is also the primary component in natural gas. Enbridge has also been investigating biogas clean up technologies with a number of different technology providers over the last few years.

1. There has been no formal training provided to Enbridge's FTEs on RNG conditioning. The existing expertise Enbridge's staff have in terms of planning, design, procurement, and construction will be utilized to build and operating the biogas conditioning facilities.
2. Please see response to (a)(i)1. above.

b) Internal standards for the RNG conditioning stations have not been developed. Enbridge will meet or exceed any applicable codes.

STAFF INTERROGATORY #9

INTERROGATORY

Issue 2 – Cost Consequences

Topic: RNG Enabling Program – Calculation of Service Fees

Ref: Exhibit B / Tab 1 / Schedule 1 / p. 18, #54 and p. 20, #59
Exhibit B, Tab 1, Schedule 1, Appendices 5-8

Preamble:
Enbridge Gas indicates that each service fee will be derived from a discounted cash flow (DCF) analysis. Also, Enbridge Gas outlines its annual revenue deficiency or sufficiency associated with the RNG Enabling Program in Appendices 5 - 8.

Questions:

a) Please identify and discuss the benefits to ratepayers of Enbridge Gas' RNG Enabling Program – Upgrading Service?

b) Please identify and discuss the benefits to ratepayers of Enbridge Gas' RNG Enabling Program – Injection Service?

c) Will these service fees be fixed over the length of the contract? Please explain.

d) For its RNG Enabling Program – Upgrading Service, how will Enbridge Gas determine the size (or capacity) for each of the site-specific facilities it intends to build?
   i) Please discuss whether some sources of RNG, such as bio-methane from landfill sources, will decline over time?
      1. Please discuss the implications to ratepayers if the feedstock for biogas declines over the next 10 years, over the next 20 years? How will Enbridge Gas mitigate these risks?

   ii) What are the implications of building upgrading facilities if the expected lifespan of the feedstock is less than service life of its upgrading facilities (e.g., the feedstock has a lifespan of 10 years, while the upgrading facilities have a service life of 20 years)? Please explain.
      1. Who will bear these risks?
      2. How will Enbridge Gas mitigate these risks?

e) For its RNG Enabling Program – Injection Service, how will Enbridge Gas determine the size (or capacity) of each of the site-specific pipelines it intends to build?
   i) What are the implications of building pipelines if the expected lifespan of the feedstock is less than service life of its pipelines (e.g., the feedstock has a lifespan of 10 years, while the pipelines have a service life of 40 years)? Please explain.
      1. Who will bear these risks?
      2. How will Enbridge Gas mitigate these risks?

f) Please identify and discuss the service fees calculation methodologies that have been approved in other jurisdictions for programs that are similar to the RNG Enabling Program – Upgrading and Injection Services. For these jurisdictions please discuss the Upgrading and Injection Services separately and include:
   i) What is the service fees calculation methodology (i.e., DCF analysis and/or full-cost based ratemaking)? Please explain.
   ii) Who bears the risk of under collections (the annual utility revenue deficiencies) related to the program (i.e., the RNG producer, the gas ratepayer, the shareholder or some combination)? Please explain.

g) For both the Upgrading and Injection Services, please specify the major cost components for the capital investment.

h) Please explain whether or not the estimated capital cost include contingency cost.
   i) If so, please provide the method, assumptions, and inputs of estimating the contingency cost.
   ii) If not, please explain what is Enbridge Gas' plan to deal with unexpected costs.

i) For the Upgrading Service, please provide the description of property/rate class used for CCA rate for each component of the plant:
   i) Energy component
   ii) Non-Energy component
   iii) Buildings component

j) For the Injection Service, please provide the description of property/rate class used for CCA rate.

k) Please explain the capital structure, return on equity, and cost of debt used in the analysis.

l) For both the Upgrading and Injection Services, please specify the major cost components for O&M expenses.
   i) Please specify the inflation rate assumption used in the analysis.

ii) What are the number of FTEs associated with its RNG Enabling Program? Did Enbridge Gas hire additional FTEs or train internal employees? Please explain.

m) For the Injection Service, Enbridge Gas assumed a municipal tax rate of 0.06%. Please explain how this rate was calculated and provide all supporting documentation including data and assumptions.

n) For the Upgrading Service, please outline Enbridge Gas' municipal tax rate assumptions included in its DCF analysis?
   i) If Enbridge Gas assumed that it would not be paying any municipal taxes, please provide the agreements with the municipalities that allowed for this?
   ii) Please redo Exhibit B, Tab 1, Schedule 1, App 5 and 6 to include a municipal tax rate. Please discuss the impact of including the municipal tax rate on Enbridge Gas' DCF analysis.

o) For both the Upgrading and Injection Services, please provide discounted cash flow analysis and complete Table 1 and Table 2 below by changing each of the following assumptions in the analysis and calculate accumulated NPV and PI for the 20 year forecast horizon (assuming the annual revenue stays at the same level as the base case).
   i) Discount rate (i.e. Cost of debt, ROE, Capital structure)
   ii) Capital investment
   iii) O&M expense

Table 1. Scenario Analysis for RNG Upgrading Service

Scenario	Annual Revenue	Accumulated NPV at Year 20	PI at Year 20
Base Case	$1,281,000	$733,495	1.100
Scenario 1(a) Base case cost of debt + 50 bps	$1,281,000		
Scenario 1(b) Base case cost of debt +100 bps	$1,281,000		
Scenario 1(c) Base case ROE+100 bps	$1,281,000		
Scenario 1(d) Base case ROE+300 bps	$1,281,000		
Scenario 1(e) 50/50 D/E ratio	$1,281,000		
Scenario 1(f) 35/65 D/E ratio	$1,281,000		
Scenario 2 Base case capital investment ($7,419,759) + 10% increase	$1,281,000		
Scenario 3 Base case O&M expense + 10% increase (Year 1 to Year 20)	$1,281,000		

Table 2. Scenario Analysis for RNG Injection Service

Scenario	Annual Revenue	Accumulated NPV at Year 20	PI at Year 20
Base Case	$725,000	$544,297	1.100
Scenario 1(a) Base case cost of debt + 50 bps	$725,000		
Scenario 1(b) Base case cost of debt +100 bps	$725,000		
Scenario 1(c) Base case ROE+100 bps	$725,000		
Scenario 1(d) Base case ROE+300 bps	$725,000		
Scenario 1(e) 50/50 D/E ratio	$725,000		
Scenario 1(f) 35/65 D/E ratio	$725,000		
Scenario 2 Base case capital investment ($5,439,025) + 10% increase	$725,000		
Scenario 3 Base case O&M expense + 10% increase (Year 1 to Year 20)	$725,000		

RESPONSE

a) The benefit to ratepayers from the RNG Enabling Program is the promotion and assurance of a supply of low-carbon RNG in Ontario. The benefits of RNG are discussed at length in the pre-filed evidence and the Company's 2018 Cap and Trade Compliance Plan. Please also see the response to APPrO Interrogatory #2(d) filed at Exhibit I.1.EGDI.APPRO.2.

b) Please see response to part (a).

c) Yes, the Rate 400 and Rate 401 service fees will be set for the life of the applicable contract. This explained at Exhibit B, Tab 1, Schedule 1, paragraph 54 and illustrated by way of an example at Exhibit B, Tab 1, Schedule 1, Appendix 6 and Appendix 7.

d) For the RNG Enabling Program – Upgrading Service, Enbridge will determine the size (or capacity) for each of the site-specific facilities it intends to build on a case by case basis working in conjunction with the biogas producer.
   i) In the case of landfill gas, the expected biogas output will tend to decline over time. However, other sources of biogas have the potential to grow over time as populations grow and creation of biomass accordingly increases (e.g., volumes of municipal waste water, source sorted organics, and agricultural waste).
      1. The Company's RNG proposals mitigate the risk of declining RNG production over time by not linking the fees for these services to RNG production volumes.

   ii) The term of the Rate 400 contract between the Company and the biogas producer will be negotiated on a case by case basis taking into account the expected lifespan of the biogas source. By doing so the implications of building upgrading facilities with an expected lifespan differing from that of the feedstock will be mitigated.
      1. Given the way the Rate 400 fees will be set, this risk will fall on the biogas producer.
      2. The Company's RNG proposals mitigate the risk of declining RNG production over time by not linking the fees for these services to RNG production volumes.

e) For the RNG Enabling Program – Injection Service, Enbridge will determine the size (or capacity) for each of the site-specific facilities it intends to build on a case by case basis working in conjunction with the biogas producer.
   i. The term of the Rate 401 contract between the Company and the biogas producer will be negotiated on a case by case basis taking into account the expected lifespan of the biogas source. By doing so the implications of building upgrading facilities with an expected lifespan differing from that of the feedstock will be mitigated.
      1. Given the way the Rate 401 fees will be set, this risk will fall on the biogas producer.
      2. The Company's RNG proposals mitigate the risk of declining RNG production over time by not linking the fees for these services to RNG production volumes.

f) i) and ii) The most relevant example is Fortis BC Energy Inc. (FEI). FEI has an RNG program dating back to 2010. Fortis offers customers the option to blend RNG with their conventional gas supply. The cost of the raw biogas, the RNG upgrading facilities and the injection station are allocated to the customers purchasing the

RNG. In the event the RNG volumes are undersubscribed the balance of the RNG cost is recovered from all FEI's non-bypass customers.

Similar to the Company's proposal, the RNG upgrading can be completed by FEI, as the regulated utility, or an independent operator.

g) Please see the Company's evidence in this proceeding (Exhibit B, Tab 1, Schedule 1, paragraphs 57 and 58) for an example of the capital and estimated operating costs for both an RNG upgrading and Injection facility.

h) The Capital cost estimate in the example includes contingency.
   i) The level of contingency is dependent on the known and unknown factors associated with the project. As a project moves from a conceptual stage closer to an executable stage the level of contingency decreases.
   ii) Please see response to h) i) above.

i)
   i) Energy component Landfill/Digester Gas Cleaning and Upgrading equipment – CCA Class 43.2 (50%)
   ii) Non-Energy component Other facilities / Balance of Plant – CCA Class 8 (20%)
   iii) Buildings component Buildings – CCA Class 1 (4%)

j) For the Injection station Enbridge utilized CCA Class 51 – Natural Gas Distribution Assets - CCA rate 6%

k) Please refer to Canadian Biogas Association Interrogatory #8 filed at Exhibit I.2.EGDI.CBA.8.

l) The operating costs for the Upgrading facility in Table 2 of Exhibit B, Tab1, Schedule 1 are as follows:

Upgrading Services O&M costs breakdown

Consumables	$204,000
Labour	$163,200
Operation and Maintenance	$81,600
Total	$448,800

The operating costs for the Injection facility in table 3 of Exhibit B, Tab1, Schedule 1 are as follows:

Injection Services O&M costs breakdown

Odourant replacement	$4,200
Measurement and Regulation	$16,500
SCADA	$71,000
Miscellaneous (account management, WMC)	$15,300
Total	$107,000

i. The inflation rate used in the example is 2%.
ii. There are approximately 3.5 FTEs working on the RNG enabling program. Enbridge has not hired any additional employees for the RNG enabling program.

m) The municipal tax rate of 0.06% was incorrect. The Company will update the Appendix 5, 6, 7, 8, with Enbridge's municipal tax rate of 0.59% from its most recent annual feasibility guidelines as a proxy estimate. The rate of 0.59% is Enbridge's trailing five year average municipal taxes expressed as a percentage of Enbridge's trailing five year average total customer-related distribution plant capital. Municipal taxes will be treated as a flow-through cost.

n) The exclusion of municipal taxes in the upgrading service was an error. The evidence and Appendix 5 and Appendix 6 will be updated to reflect the inclusion of municipal taxes.

o) i) to iii) Tables 1 and 2 have been updated with the specific scenario analysis on the RNG upgrading and injection services shown below. The annual revenue detailed in the table, include the updated municipal tax

Table 1. Scenario Analysis for RNG Upgrading Service

Scenario	Annual Revenue	Accumulated NPV at Year 20	PI at Year 20
Base Case	$ 1,329,000	$ 731,134	1.100
Scenario 1(a) Base case cost of debt + 50 bps	$ 1,329,000	$ 605,101	1.083
Scenario 1(b) Base case cost of debt + 100 bps	$ 1,329,000	$ 482,670	1.066
Scenario 1(c) Base case ROE + 100 bps	$ 1,329,000	$ 534,900	1.073
Scenario 1(d) Base case ROE + 300 bps	$ 1,329,000	$ 168,067	1.023

Table 1. Scenario Analysis for RNG Upgrading Service			
Scenario	Annual Revenue	Accumulated NPV at Year 20	PI at Year 20
Scenario 1(e) 50/50 D/E ratio	$ 1,329,000	$ 311,996	1.043
Scenario 1(f) 35/65 D/E ratio	$ 1,329,000	$ (88,010)	0.988
Scenario 2 Base case capital investment ($7,419,759)+10% increase	$ 1,329,000	$ 124,273	1.015
Scenario 3 Base case O&M expense +10% increase (Year 1 to Year 20)	$ 1,329,000	$ 277,926	1.038

Table 2. Scenario Analysis for RNG Injection Service			
Scenario	Annual Revenue	Accumulated NPV at Year 20	PI at Year 20
Base Case	$ 757,000	$ 545,619	1.100
Scenario 1(a) Base case cost of debt + 50 bps	$ 757,000	$ 437,435	1.080
Scenario 1(b) Base case cost of debt + 100 bps	$ 757,000	$ 332,480	1.061
Scenario 1(c) Base csae ROE + 100 bps	$ 757,000	$ 377,238	1.069
Scenario 1(d) Base case ROE + 300 bps	$ 757,000	$ 63,375	1.012
Scenario 1(e) 50/50 D/E ratio	$ 757,000	$ 186,385	1.034
Scenario 1(f) 35/65 D/E ratio	$ 757,000	$ (155,077)	0.971
Scenario 2 Base case capital investment ($7,419,759)+10% increase	$ 757,000	$ 43,588	1.007
Scenario 3 Base case O&M expense +10% increase (Year 1 to Year 20)	$ 757,000	$ 433,586	1.080

STAFF INTERROGATORY #10

INTERROGATORY

Issue 2 – Cost Consequences

Topic: Geothermal Energy Service (GES) Program

Ref: Exhibit B / Tab 1 / Schedule 1 / pp. 21-22 and p. 25, #74

Preamble:
Enbridge Gas indicates that it plans to implement its GES Program in 2018 as a GHG emission abatement program to offset gas usage.

Enbridge Gas also indicates that geothermal systems provides space heating, water heating and cooling are typically electrically powered.

Enbridge Gas states that it sees geothermal as a key way to abate carbon. Deploying geothermal systems where natural gas would otherwise be consumed will offset natural gas usage.

Questions:

a) Please explain whether Enbridge Gas' GES Program is to install ground-source heat pumps in natural gas heated homes only?

   i) Please confirm that Enbridge Gas' GES Program does not include installing ground-source heat pumps in electrically heated homes?

   ii) Please confirm that Enbridge Gas' GES Program does not include installing ground-source heat pumps in propane-heated home?

b) Please explain in detail why Enbridge Gas is proposing to implement this Program given that the technology is shown on the OEB's Marginal Abatement Cost Curve[7] (OEB MACC) to be high cost activity compared to other energy efficiency options for space heating.

c) Please outline Enbridge Gas' analysis to demonstrate that installing a geothermal energy system in a gas heated home will be cost-effective for a typical residential customer (e.g., when a heat pump is installed in a gas heated home, the net impact of the customer's electricity bill and natural gas bill would be reduced overall for years 1 to 10).
   i) If Enbridge Gas has not completed this analysis, please conduct this analysis and provide all supporting documentation including data, assumptions and analysis.

RESPONSE

a) The Board's Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities encourages the utility to consider abatement of GHG emissions as one tool in meeting its current and future carbon obligations. To that effect, this program will include existing natural gas customers, forecasted natural gas customers or expansion areas and electric, propane or other fuel customers who are in the Company's franchise area could choose to be natural gas customers.

   Enbridge has proposed that its Geothermal Energy Service would be provided as part of its regulated utility business such that this service displaces natural gas consumption in existing buildings and newly constructed buildings that would otherwise rely on natural gas for their space and water heating requirements. To the extent that this service is subscribed to by buildings that cannot be practically served by the Company's gas distribution system, this segment of the Geothermal Energy Service may be undertaken by Enbridge on a non-utility basis.

   (i) Not confirmed. Please see the response to part (a) above.

   (ii) Not confirmed. Please see the response to part (a) above.

b) In its analysis, the Board's Marginal Abatement Cost Curve study did not take into account funding from the CCAP and in the case of geothermal systems this changes the business case.

c) and i) Please see table below that shows the 10 year operating cost comparison between a natural gas and a geothermal home

Comparison between a Geothermal Home and Gas Home

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy Costs										
Gas Cost (Per Cubic Meters) in Cents	35.40	36.30	37.79	38.89	39.78	40.49	41.18	41.84	42.09	42.59
Cost of carbon (Per Tonne) in $	17.00	18.00	18.00	19.00	20.00	21.00	31.00	36.00	43.00	50.00
Electricity Cost (per kWh) in Cents	10.62	11.17	11.43	11.76	12.58	13.38	14.34	14.88	15.28	15.66
Natural Gas Home										
Gas consumption for heating (Cubic meter)	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Gas consumption for hot water (Cubic meter)	500	500	500	500	500	500	500	500	500	500
Carbon (Tonnes)	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Air conditioner electricity usage (kWh)	2,400.0	2,400.0	2,400.0	2,400.0	2,400.0	2,400.0	2,400.0	2,400.0	2,400.0	2,400.0
Furnace electricity consumption (kWh)	1,100.0	1,100.0	1,100.0	1,100.0	1,100.0	1,100.0	1,100.0	1,100.0	1,100.0	1,100.0
Gas Cost in $	849.5	871.2	907.0	933.3	954.6	971.8	988.4	1,004.1	1,010.1	1,022.2
Carbon cost in $	76.5	81.0	81.0	85.5	90.0	94.5	139.5	162.0	193.5	225.0
Electricity costs in $	371.6	391.0	400.2	411.7	440.2	468.3	501.7	521.0	534.6	548.2
Total energy related costs $	**1,297.7**	**1,343.2**	**1,388.1**	**1,430.4**	**1,484.8**	**1,534.7**	**1,629.6**	**1,687.0**	**1,738.2**	**1,795.4**
Geothermal Home										
Cooling electricity consumption (kWh)	1,267.2	1,267.2	1,267.2	1,267.2	1,267.2	1,267.2	1,267.2	1,267.2	1,267.2	1,267.2
Heating electricity consumption (kWh)	4,675.5	4,675.5	4,675.5	4,675.5	4,675.5	4,675.5	4,675.5	4,675.5	4,675.5	4,675.5
Hot water electricity consumption (kWh)	1,945.0	1,945.0	1,945.0	1,945.0	1,945.0	1,945.0	1,945.0	1,945.0	1,945.0	1,945.0
Electricity costs in $	837.6	881.1	901.9	927.7	992.0	1,055.5	1,130.7	1,174.1	1,204.9	1,235.5
Total energy related costs $	**837.6**	**881.1**	**901.9**	**927.7**	**992.0**	**1,055.5**	**1,130.7**	**1,174.1**	**1,204.9**	**1,235.5**
Assumptions										
Gas Furnace efficiency = 0.95										
Gas water heater efficiency = 0.62										
Air conditioner efficiency = 15 SEER										
Ground source heat pump efficiency based on manufacturer specification data: Winter COP = 4; Summer COP = 7.5										
Cooling season from May 15 - Sept 15 (4 months)										
Gas furnace electricity consumption based on 2013 NYSERDA Gas Furnace Electricity Usage Study										
Geothermal water heating consumption pro-rated based on winter/summer months with 50% geothermal and 50% electric coverage										
Carbon cost = 1.875 kg/m3 emission factor										
Electricity rates are based on the Toronto Hydro residential rate effective May 1, 2018 (excludes fixed charges)										
Natural gas current rates are based on the Enbridge Gas Distribution Inc. rate schedule EB-2018-0090, effective Apr 1, 2018										

STAFF INTERROGATORY #11

INTERROGATORY

Issue 2 – Cost Consequences

Topic: Geothermal Energy Service (GES) Program

Ref: Exhibit B / Tab 1 / Schedule 1 / pp. 21-22

Preamble:
Enbridge Gas proposes to implement in 2018 its GES Program.

In Enbridge Gas' 2018 Compliance Plan (EB-2017-0224, Exhibit C / Tab 5 / Schedule 2 / p. 3, Table 1) it outlines a summary of its proposed abatement initiatives and required approvals:

Table 1: Abatement Initiatives Summary

Initiative Development Stage	Initiative	2018 OEB Approvals Required
Stage 3: Propose	Renewable Natural Gas Procurement	Approval to procure RNG in 2018 as per the model identified in this exhibit.
	Natural Gas Renewable Enabling Program	Approval of new rates for RNG processing and injection, and approval to record deficiency and sufficiency in the applicable variance account. This program will be addressed in EB-2017-0319.
	Geothermal Energy Services Program	Approval of geothermal energy service fees and approval to record deficiency and sufficiency in the applicable variance account. This program will be addressed in EB-2017-0319.
Stage 2: Formulate	Hydrogen (Power to Gas)	Approval for 2 FTEs to support investigation, planning and project management activities, to be funded through the GGEIDA. Approval of funding of up to $2M starting in 2018 in the Low Carbon Innovation Fund ("LCIF") to advance pilot projects and research throughout stages one to three of the Initiative Funnel that would enable a more complete assessment of promising technologies and opportunities for eventual implementation. The LCIF would be tracked through the GGEIDA.
	Net-Zero Homes/ Micro-Generation	
	Expanded NGV Program	
	Natural Gas Air-Source Heat Pumps	
Stage 1: Conceptual	Smart Metering	
	RNG – Gasification	
	Carbon Capture	
Implementation / Existing Activity	Demand Side Management	Enbridge's 2015 to 2020 DSM Plan has already been approved in EB-2015-0029/49. The DSM mid-term review which as one component is assessing the interconnection between DSM and Cap and Trade is in progress (EB-2017-0127 and EB-2017-0129)
	Green Investment Fund Program	Enbridge's incremental residential energy efficiency abatement through the Green Investment Fund has been in place since 2016 and does not require an approval through this 2018 Compliance Plan.

Questions:

a) Please confirm that Enbridge Gas' GES Program refers to ground-source heat pumps only.

b) In Table 1 above, natural gas air-source heat pumps are in stage 2 of Enbridge Gas' Abatement Construct. Please explain whether Enbridge Gas intends to expand its GES Program to include natural gas air-source heat pumps?
   i) If yes, please explain the timing, resources and costs?

RESPONSE

a) Confirmed. The reference in the table is to ground source geothermal systems, not to air source heat pump systems.

b) The GES program is for ground source heat pumps only and not air source heat pumps.
   i) Not applicable.

STAFF INTERROGATORY #12

INTERROGATORY

Issue 2 – Cost Consequences

Topic: Geothermal Energy Service (GES) Program

Ref: Exhibit B / Tab 1 / Schedule 1 / p. 24, #69 and p. 26, #76 and #77

Preamble:
Enbridge Gas indicates that it plans to offer this Program to the residential market. For customers that participate in this Program, Enbridge Gas will supply and install separate geothermal loops for each home or building owner.

Enbridge Gas also states that the home or building owner will arrange for the installation of the ground source heat pump and other equipment necessary to complete the geothermal energy system. Enbridge Gas will provide support to the customer to ensure that the appropriate equipment is procured and installed.

Questions:

a) Please explain what Enbridge Gas means by the residential market (e.g., single family homes, multi-family homes, etc.)?

b) Please explain how Enbridge Gas intends to promote its GES Program to improve residential customer awareness? What are the estimated resources and costs associated with this activity in 2018, 2019 and years 3 – 21? Would these costs be included in its Cap and Trade GGEIDA? Please explain.

c) Please explain what Enbridge Gas means by the home owner will arrange for the installation of the ground source heat pump system. For example, does this mean that a home owner is responsible for: 1) procuring a geothermal energy system from a supplier and 2) contracting for the installation of that system? \
   i) If so, does Enbridge Gas intend to work with OGA member suppliers and contractors to implement its GES program? Please explain.
      1. Does Enbridge Gas intend to use the same contractor to install its geothermal loops that the customer will use to install its geothermal system? Please explain.
      2. Does Enbridge Gas intend to use internal resources to install the geothermal loops? Please explain. (a) If yes, please outline the resources and costs in 2018, 2019 and years 3-21?

3. Please explain in detail how Enbridge Gas intends to provide support to the customer to ensure that the appropriate equipment is procured and installed?

d) Please explain whether a geothermal energy system (i.e., ground-source heat pump system) that a customer procures typically includes the geothermal loops?
   i) Are geothermal loops typically sold separately from the geothermal energy system? Please explain.
      1. If so, how much does a geothermal loop cost in the marketplace?
      2. What percentage of the costs does geothermal loops represent compared to the cost of a geothermal energy system (e.g., 25%, 50%, etc.)?

e) Does Enbridge Gas intend to enter into a service agreement with the geothermal energy supplier and/or installation contractor? If yes, please provide the service agreement.
   i) Will these be standardized agreements?
   ii) What is expected length of the contracts?

RESPONSE

a) By “residential market”, Enbridge is referring to the low density residential market including detached, semi-detached, and townhomes and low rise townhomes.

b) Enbridge will leverage its existing relationships with developers and builders to promote this technology in lieu of natural gas. Additionally, Enbridge intends to use digital marketing in the form of a website page to provide more information to its potential customers.

   $100,000 per year is estimated for marketing costs for the 10 year forecast period. Additionally, one full time marketing resource is estimated for 2018, 2019 and 2020 with an additional marketing resource estimated for years beyond that. The costs associated with these items are included in Enbridge’s DCF model to set fees for the Geothermal Energy Service. The Company has not hired any resources or incurred any marketing costs pending the outcome of this proceeding.

c) Similar to how the current natural gas and furnace installation and procurement works, the home owner or builder will arrange for the installation of the heat pump system. Enbridge will contract, procure and install the underground geothermal loop. Enbridge will also ensure that the geothermal loop sizing is appropriate for the specified heat pump and size of home and will inspect and quality assure the

commissioning of the system (Heat pump and Geothermal loop) to ensure the system works.

i) OGA members consist of drilling contractors as well as heat pump suppliers. Enbridge will not contract with any heat pump suppliers for the supply of the heat pump system which is the responsibility of the customers. Enbridge will contract for the installation of the underground geothermal loops.
   1. This would depend on the circumstances and the contractor's ability and willingness to provide both services.
   2. Enbridge does not intend to use internal resources to install geothermal loops at this time.
   a. Not applicable.
   3. Enbridge will design an installation and maintenance standard that will have to be adhered to and an inspection process in conjunction with the commissioning of the ground source heat pump system.

Geothermal systems typically include the underground geothermal loops and the internal heat pump system. The costs for each component may be separately identified or may be part of an overall price.

1. Costs of geothermal loops vary by geography, soil condition. A typical horizontal geothermal loop costs between $1,300 to $1,800 per tonne of heating capacity. A vertical drilled loop costs between $2,500 to $4,500 per tonne of heating capacity.
2. For a vertical loop geothermal system, the costs are up to 50% of the total system costs and for horizontal systems the costs are roughly 25% of the total system costs.

d) Enbridge will contract with qualified geothermal drillers (some of whom may be OGA members).

i) The nature of these agreements/contracts have not been determined.
ii) The length of these agreements/contracts have not been determined.

STAFF INTERROGATORY #13

INTERROGATORY

Issue 2 – Cost Consequences

Topic: Geothermal Energy Service (GES) Program – Calculation of Service Fees

Ref: Exhibit B / Tab 1 / Schedule 1 / pp. 27-28, #79, #80, #81 and #83

Preamble:
Enbridge Gas states that it has built a DCF model using a 10-year customer forecast and it expects about 170 customers in year 1 and over a 10-year period about 18,000 customers. This is based on expected demand, current capacity in the market and ramp up capability of the market to meet demand.

Enbridge Gas also states that costs may depend on geographical and geological construction uncertainties.

Questions:

a) Please explain whether Enbridge Gas assumed that a ground-source heat pumps used and useful life is 40 years.

b) Please explain how Enbridge Gas determined that 170 customers in year 1 would purchase geothermal energy systems (e.g., did Enbridge Gas survey customers, etc.)? Please provide all supporting documentation including data, assumptions and analysis.
   i) Please explain whether the 170 customers are customers of Enbridge Gas (i.e., connected to Enbridge Gas' distribution system)?
   ii) Please breakdown the forecast of 170 customers by geographical area and discuss the geological construction uncertainties for each of the areas.

c) Please explain how Enbridge Gas determined that 18,000 customers by year 10 would purchase geothermal energy systems (e.g., did Enbridge Gas survey customers, etc.)? Please provide all supporting documentation including data, assumptions and analysis.
   i) Please explain whether the forecast of 18,000 customers are customers of Enbridge Gas?

ii) Please breakdown the forecast of 18,000 customers by geographical area and discuss the geological construction uncertainties for each of the areas.

d) Please explain what is the expected demand over the ten year period? Please provide all supporting documentation including data, assumptions and analysis.

e) Please explain what is the current capacity in the market? Please provide all supporting documentation including data, assumptions and analysis.

f) Please complete Table 3 below for the 10-year period:

Table 3 – Customers per Housing Stock				
	Year 1	Year 2……	Year 3….to	……Year 10
Existing Home with Gas Heating (switch to electrical heating with GES Program)	# customers			
New Construction – Gas Heating (switch to electrical heating with GES Program)	# customers			
Total – No. of Customers	170	300…..		18,000

i) For Table 1, if Enbridge Gas has estimated customers in different types of dwellings than the ones listed above, please modify the table and complete.

g) Please complete Table 4 below for the 10-year period:

Table 4 – Reductions to GHG Emissions per Housing Stock				
	Year 1	Year 2……	Year 3….to	……Year 10
Existing Home with Gas Heating (switch to electrical heating with GES Program)	GHG emissions			
New Construction – Gas Heating (switch to electrical heating with GES Program)	GHG emissions			
Total – GHG emissions				

i) For Table 4, if Enbridge Gas has estimated customers in different types of dwellings than the ones listed above, please modify the table and complete.

ii) Based on Table 4, please explain how the GHG emission reductions will impact Enbridge Gas' 2018 throughput (Ex B, T2, Sch 1, p. 6, Table 1) and GHG emission forecasts (Ex B, T3, Sch 1, p.3, Table 1) as outlined in its 2018 Compliance Plan (EB-2017-0224).

1. Based on Table 4 above, please explain how the GHG emissions will impact Enbridge Gas' expected throughput in years 2 – 10? Please provide all supporting documentation including data, assumptions and analysis.

RESPONSE

a) Enbridge has assumed a useful life of 30 years for the geothermal loops. Enbridge has provided a 40 year analysis based on a 10 year customer add forecast and a 30 year useful life.

b) i) and ii) The Company has assumed a mix of new construction and retrofit market customers as shown in the table below. Enbridge was informed by a survey conducted by Ipsos. This survey is included as Attachment 1 to this response. The Company not did not develop its customer addition forecast by geographical area. The breakdown of customers is shown in Table 3 in response to question f) below.

Enbridge made the following assumptions in determining the forecast:

New construction market:

- Currently around 30,000 units a year.
- The first year add is constrained by vertical drilling capacity which Enbridge estimates to be 100 units.
- The Company expects vertical drilling capacity to increase to 200, 300, 600, 900 and 1800 in the subsequent years, with Enbridge involvement providing confidence in the new construction market for these services until geothermal can capture about 10% of the market in year 7 of 3,000 units a year. The 3,000 units a year is assumed to be steady state forward. Enbridge assumes that 90% of these units could choose to be natural gas customers.

Retrofit market

- Enbridge expects very few conversions from existing natural gas customers to geothermal.
- There are currently 800,000 homes in Ontario without natural gas. Roughly 67% of these have a forced air system which makes it economic to retrofit a geothermal system without ducting changes when it comes time to install a new heating system. On average, homeowners change their heating systems once every 20 years.
- Enbridge assumes that approximately 20% of this potential retrofit market could choose to become natural gas customers. The Company estimates that 10% of those homeowners would choose Enbridge's Geothermal Energy Service.

c) i) and ii) Please refer to the answer to part b) above and the response to Board Staff 10 (a) filed at Exhibit I.2.EGDI.STAFF.10.

d) The geothermal industry in Ontario is fragmented and has previously seen spikes in uptake due to Government subsidies. The forecasted demand for geothermal is dependent on various factors including the approval of this application which will enable faster adoption in the residential market.

It is the Company's belief that given the Provincial mandate to enable lower carbon solutions for home heating, and increasing cost of fossil fuels due to the Cap and Trade program, the demand for geothermal systems will accelerate in Ontario.

e) At present, residential geothermal systems are largely installed in rural areas where homes are heated with propane, oil, or electricity. In a majority of cases, rural properties have sufficient land to install horizontal loops. However, in more urban areas, and in new construction applications, loops will have to be installed vertically due to space constraints.

Currently, there is sufficient capacity in the market for geothermal system installation to meet demand. However, as demand increases, and urbanization of systems occurs, a lack of available drilling capacity has the potential to limit residential geothermal market penetration. However, as demand increases (driven by the GreenOn rebate program and the complementary Enbridge Geothermal Energy Services Program) more vertical drillers can be expected to enter the market.

Enbridge will have a vested interest in the expansion of driller capacity in the Province, and also ensuring the quality of the loops being installed. Properly installed and grouted loops are critical to the proper operation of a geothermal system. The OGA also acknowledged this shortcoming and is committed to working with Enbridge to investigate and implement driller/loop installation specific training. Partnership with community colleges to develop and deliver geothermal specific training is another avenue to be investigated as the industry scales and matures.

f) Please see the table below.

Table 3 – Customers per Housing Stock (number of customers)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Existing Home that could be gas, propane, oil or electrically heated (switch to electrical heating with GES Program)	80	120	160	200	320	440	520	520	520	520

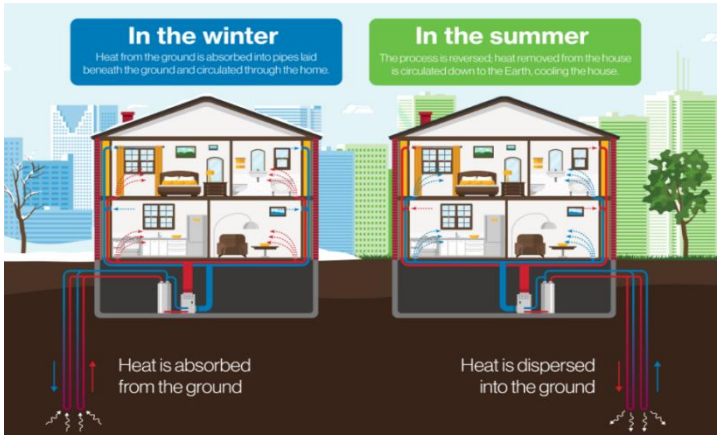
Table 3 – Customers per Housing Stock (number of customers)										
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
New Construction – Gas Heating (switch to electrical heating with GES Program)	90	180	270	540	900	1,800	2,700	2,700	2,700	2,700
Total – No. of Customers	170	300	430	740	1,220	2,240	3,220	3,220	3,220	3,220

i) Enbridge has not developed estimated for different types of dwellings other than those listed above. The retrofit customers will include propane, heating oil or other fossil fuel customers who are in the natural gas franchise and could choose to be natural gas customers in the future. The Company believes that the conversions or retrofit customers will be mostly from propane, oil or electricity rather than natural gas as the economics and pay back for the customer is substantially better.

g) Please see the Attachment to the response to OGA Interrogatory #4 filed at Exhibit I.1.EGDI.OGA.4.
   i) Please see the response to f) i) above.
   ii) As shown in the Attachment to the response to OGA Interrogatory #4 filed at Exhibit I.1.EGDI.OGA.4, the GHG reductions from the Geothermal Energy Services program in 2018 are forecasted to reduce the GHG emissions as outlined in the 2018 Compliance Plan by 765 tCO_2e, which is equivalent to a volume reduction of 390,000 m^3.
      1. The emissions reductions and corresponding volume reductions expected in years two to ten are shown in the Attachment to OGA Interrogatory #4 filed at I.1.EGDI.OGA.4. This is based on the assumption that existing homes switching to geothermal would avoid using 2,400 m^3 of natural gas per year, and a new construction home would avoid using 2,200 m^3 of natural gas per year.

Ipsos Public Affairs

ENBRIDGE



Geothermal Research

FINAL REPORT

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Study Reference CR-831

GAME CHANGERS Ipsos

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Objectives & Methodology

PURPOSE

The purpose of this research is to provide Enbridge Gas Distribution with insights into the attitudes and opinions of homeowners towards installing geothermal heating and cooling systems.

SAMPLE SIZE METHOD

A total of n=350 online interviews were conducted among homeowners in Ontario who live within Enbridge Gas Distribution's franchise area, but outside of it's delivery area. In order to qualify for the survey, homeowners must reside in detached, semi-detached, or townhouses (that have backyards with grass) and who use propane, oil, or electricity to heat their home.

FIELD DATES

September 7th to September 18th, 2017.

SURVEY LENGTH

The average interview was 10 minutes in length.

REPORTING CONVENTIONS

Statistically significant differences between demographic groups have been identified with shaded boxes – **green boxes** are used to identify that one group is statistically higher than the other and **red boxes** when it is statistically lower.

Throughout the report totals may not add to 100% due to rounding or because the question is a multi-select question, where respondents were permitted to choose more than one response.

KEY FINDINGS

Key Findings

- Cost is a significant barrier for homeowners when considering the replacement of their current heating and cooling system to a geothermal system and the provision of various financing options does not motivate a significant number of homeowners to seriously consider geothermal technology as an alternative to more traditional heating and cooling equipment.
- Initially, about four in ten (39%) homeowners indicate that they would be likely to undertake the conversion, knowing that they could reduce their annual energy costs by 60%, although only 9% of homeowners mention that they would be 'very likely' to consider a geothermal system.
- However, once learning about the initial investment required and the number of years to payback, interest in conversion drops dramatically to only 2% of homeowners who would be 'very likely' and 15% who would be 'somewhat likely' to install a geothermal heating and cooling system knowing that they would recuperate the costs of the investment over a number of years.
- The various financing options presented to homeowners through the research has a limited impact in motiving homeowners to undergo the conversion to geothermal. The option of applying for a government subsidy of $12,000 to cover the costs of conversion would motivate fewer than a quarter of homeowners (23%), while only 5% mention that they would be 'very likely'.
- Further, the option of applying for the government subsidy and renting the geothermal loop from Enbridge would only motivate one in five (20%) homeowners, with only 3% of homeowners indicating that they would be 'very likely' to convert to geothermal system, which is similar (if not slightly lower) than the application of the government subsidy alone.
- Furthermore, the majority (65%) of homeowners who indicate a likelihood to convert to a geothermal system (under any financing option) indicate that they would wait until their existing heating and cooling equipment would need to be replaced, while 26% who are likely to convert to geothermal would make the switch before their existing equipment needs to be replaced.

Key Findings

- Among those who expect to install a geothermal system, 16% would do it within the next 1 to 2 years, 31% would plan for the next 3 – 5 years, and just over half (53%) would wait more than 5 years.
- If all things are considered equal, a majority (56%) of homeowners would be likely to install a new geothermal system when their existing system is at the end of its useful lifespan. Meaning that, if a critical mass of homeowners are to be motivated to install a geothermal system, the cost associated with such a system must be equal to converting to a more traditional system, while the cost has to be even lower to likely entice those homeowners who have some existing life in their current heating and cooling system.
- On the other hand, homeowners do show a strong interest in purchasing a geothermal system if they were purchasing a newly built home, as about half (55%) of homeowners would do so, compared to only 19% who would install a natural gas-based system. Thus, promoting a geothermal system for new homebuyers would generate more interest compared to homeowners who already have an existing heating and cooling system.
- Finally, the Enbridge brand has a limited impact on homeowners' decision to convert to a geothermal system (an one that has a piping system installed and maintained by Enbridge) as only about one quarter (23%) of homeowners say the Enbridge brand gives them 'peace of mind', one-third (37%) say the Enbridge name does not have any impact on their decision, while four in ten (41%) are not sure.

Key Findings – Potential Target Market

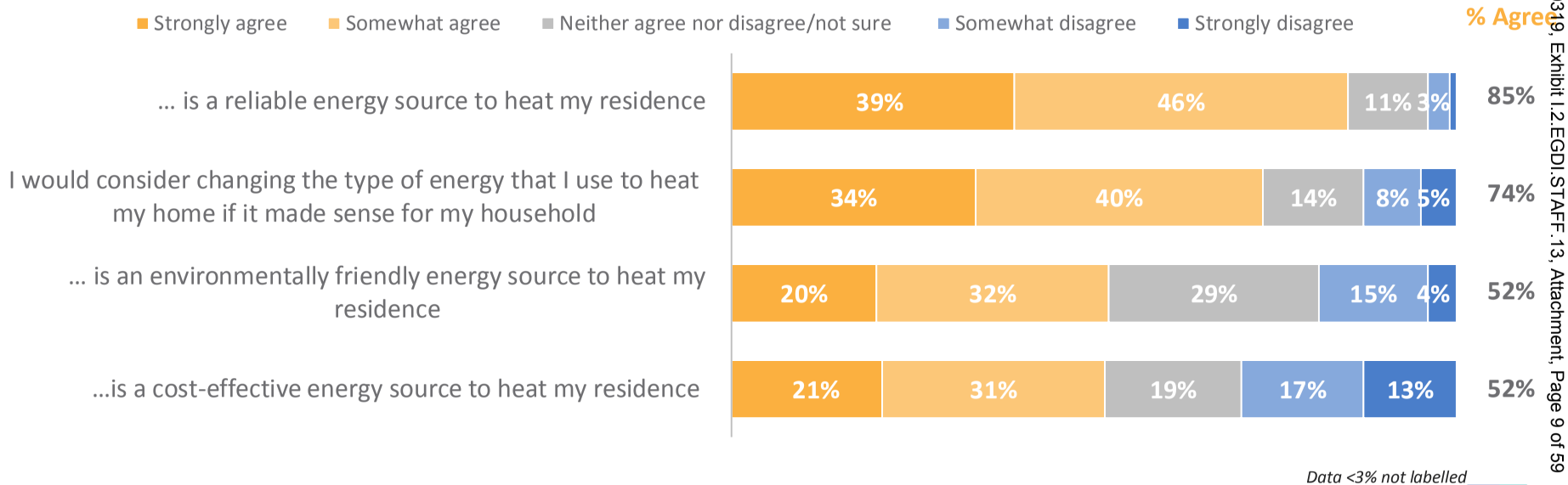
- The following groups show the greatest interest in converting to a geothermal heating and cooling system if the geothermal pipping loop is installed and maintained by Enbridge. Note that the proportion of those who would be 'very likely' is relatively small.

Target Group	% Very Likely	% Somewhat Likely	% Likely (Very + Somewhat)
Household Income $80,000+	4%	27%	31%
Use Electric Baseboards to Heat	5%	22%	27%
Knowledgeable about Geothermal Technology	5%	21%	26%
Energy Independence is Appealing	4%	21%	25%
Homeowner under the age of 55	4%	20%	24%
Heating and AC Equipment 10+ years	6%	18%	24%
Use Electricity as Primary Energy Source	2%	22%	24%
Use Oil as Primary Energy Source	6%	16%	22%

ATTITUDES ABOUT CURRENT SOURCES OF ENERGY USED IN THE HOME

Attitudes About Different Sources of Energy

- At over eight in ten (85%), the vast majority of homeowners believe the type of energy they currently use to heat their home is reliable, though three quarters (74%) say they would consider changing it and only about half (52%) think what they currently use is cost-effective or environmentally friendly.



Data <3% not labelled

Q8. Thinking about using [insert primary heating energy from Q1 electricity/propane/oil] as a source of energy to heat your residence, would you strongly agree, somewhat agree, somewhat disagree, or strongly disagree with the following statements?
Base: All Respondents (n=350)

Attitudes About Different Sources of Energy – By Key Groups

- Homeowners who have newer heating equipment (0-5 years old) or currently use propane to heat their home are more likely to agree that they use a cost-effective and environmentally friendly energy source. However, those who currently have electric baseboards in their home are less likely to agree that it is a cost-effective energy source.

% Agree

	Total	Type of Energy Used to Heat Home			Type of Heating Equipment Used		Age of Heating Equipment		
		Electricity	Propane	Oil	Electric Baseboards	Forced Air Furnace	0-5 Years	6-10 Years	Over 10 Years
Base	*350*	*82**	*152*	*116*	*40**	*299*	*129*	*78**	*143*
… is a reliable energy source to heat my residence	85%	74%	91%	85%	82%	86%	89%	86%	82%
I would consider changing the type of energy that I use to heat my home if it made sense for my household	74%	73%	68%	81%	65%	75%	70%	78%	75%
… is an environmentally friendly energy source to heat my residence	52%	54%	75%	21%	55%	51%	68%	46%	41%
…is a cost-effective energy source to heat my residence	52%	26%	76%	39%	32%	54%	65%	50%	41%

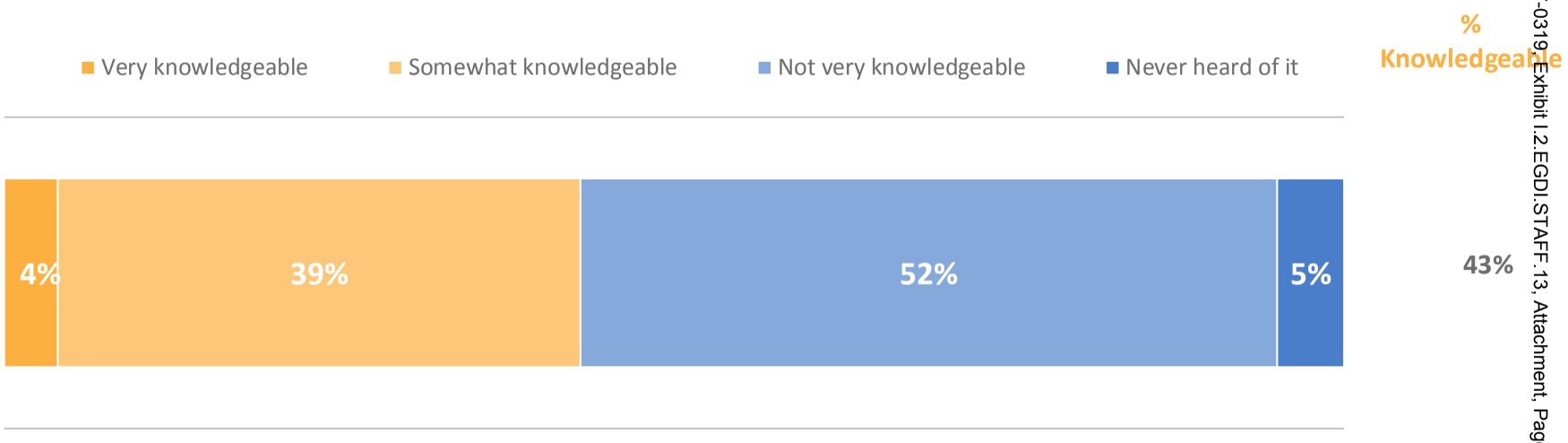
**Small base*
***Extremely small base*

Q8. Thinking about using [insert primary heating energy from Q1 electricity/propane/oil] as a source of energy to heat your residence, would you strongly agree, somewhat agree, somewhat disagree, or strongly disagree with the following statements?
Base: All Respondents (n=350)

KNOWLEDGE & APPEAL OF GEOTHERMAL HEATING & COOLING

Knowledge of Geothermal Heating & Cooling Systems

- Around four in ten (43%) homeowners claim to have at least some knowledge of geothermal heating and cooling systems, though very few (4%) say they are 'very knowledgeable', while four in ten (39%) are 'somewhat knowledgeable'.



Q11. How knowledgeable would you say that you are about geothermal or ground source heating and cooling systems for homes?
Base: All Respondents (n=350)

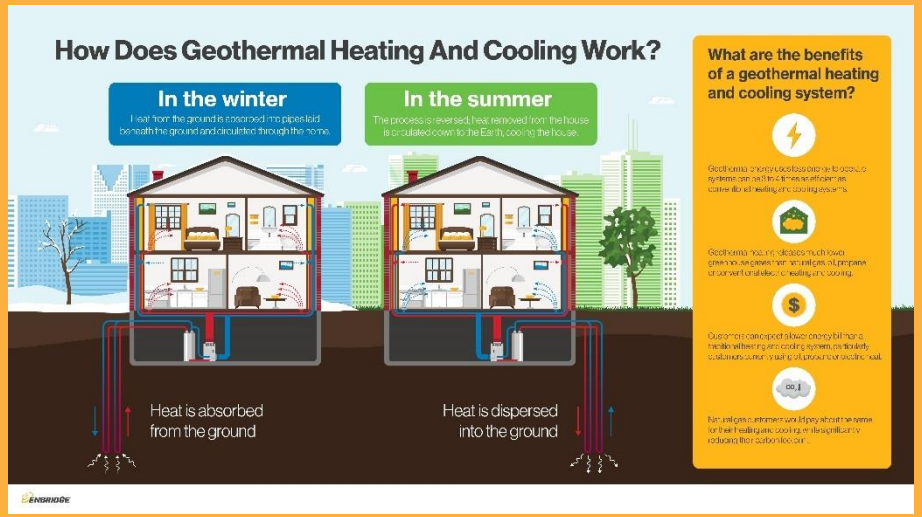
Respondents were provided this description of geothermal technology:

As you may know, a geothermal or ground source system uses a heat pump to extract heat from the earth in the winter to heat your home. The system can also be used to heat hot water.

In the summer, the process is reversed and your home is cooled by extracting heat from the home and dispersing it into the cooler earth.

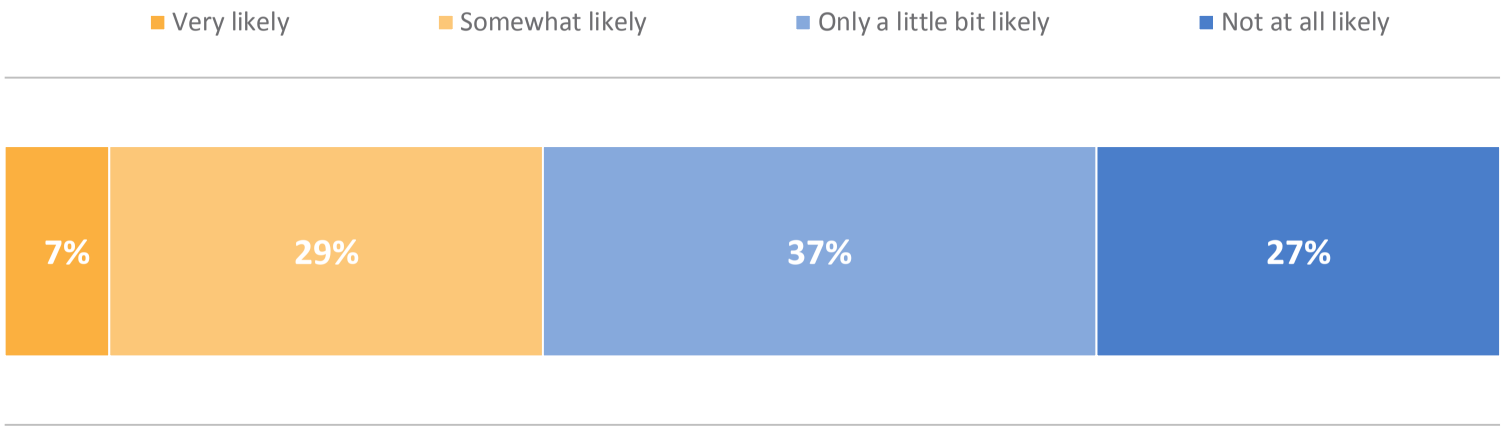
Because a geothermal system uses the earth's thermal energy to heat and cool your home, it is more efficient than traditional heating and cooling systems which results in lower annual operating costs compared to most other energy sources.

The graphic below shows how a geothermal or ground source heating and cooling system works. A geothermal system requires a piping system to be installed in the ground to either absorb or disperse heat. A geothermal system also requires ducts similar to a forced-air furnace or central air conditioning system to distribute hot and cold air in your home. The heat pump itself looks very much like a traditional forced air furnace and also eliminates the need for an air conditioning unit outside your home.



Likelihood to Seek Information About Installing Geothermal

- Only about one third (36%) of homeowners feel inclined to seek out more information regarding geothermal heating and cooling systems for their home.



Q12. How likely would you be to seek out more information about installing a geothermal heating and cooling system for your home?
Base: All Respondents (n=350)

Likelihood to Seek Information About Installing Geothermal – By Key Groups

- Homeowners who currently use propane to heat their home are less likely to be interested in seeking information about geothermal compared to those who are using electricity or oil.

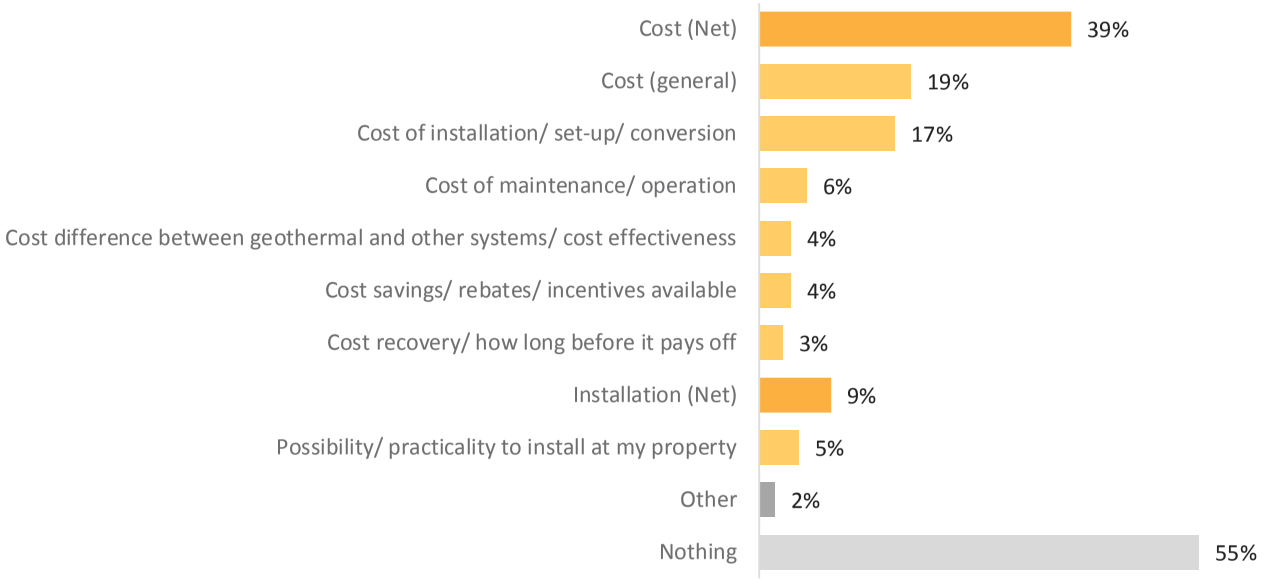
	Total	Type of Energy Used to Heat Home			Type of Heating Equipment Used		Knowledge of Geothermal	
		Electricity	Propane	Oil	Electric Baseboards	Forced Air Furnace	Very/ Somewhat Knowledgeable	Not Very Knowledgeable / Never Heard of it
Base	*350*	*82**	*152*	*116*	*40**	*299*	*150*	*200*
Very/Somewhat likely	36%	41%	28%	42%	42%	35%	41%	32%
Only a little bit/Not at all likely	64%	59%	72%	58%	58%	65%	59%	68%

**Small base*
***Extremely small base*

Q12. How likely would you be to seek out more information about installing a geothermal heating and cooling system for your home?
Base: All Respondents (n=350)

Information Would Like to Know About Geothermal

- When asked if there is any kind of information they would like to know about geothermal heating and cooling systems, most homeowners (55%) provide no response. Of those that do provide a response, the highest proportion cite information related to cost (39%) – specifically the cost in general about the system (19%) or the cost of installation/ set-up/ conversion (17%).

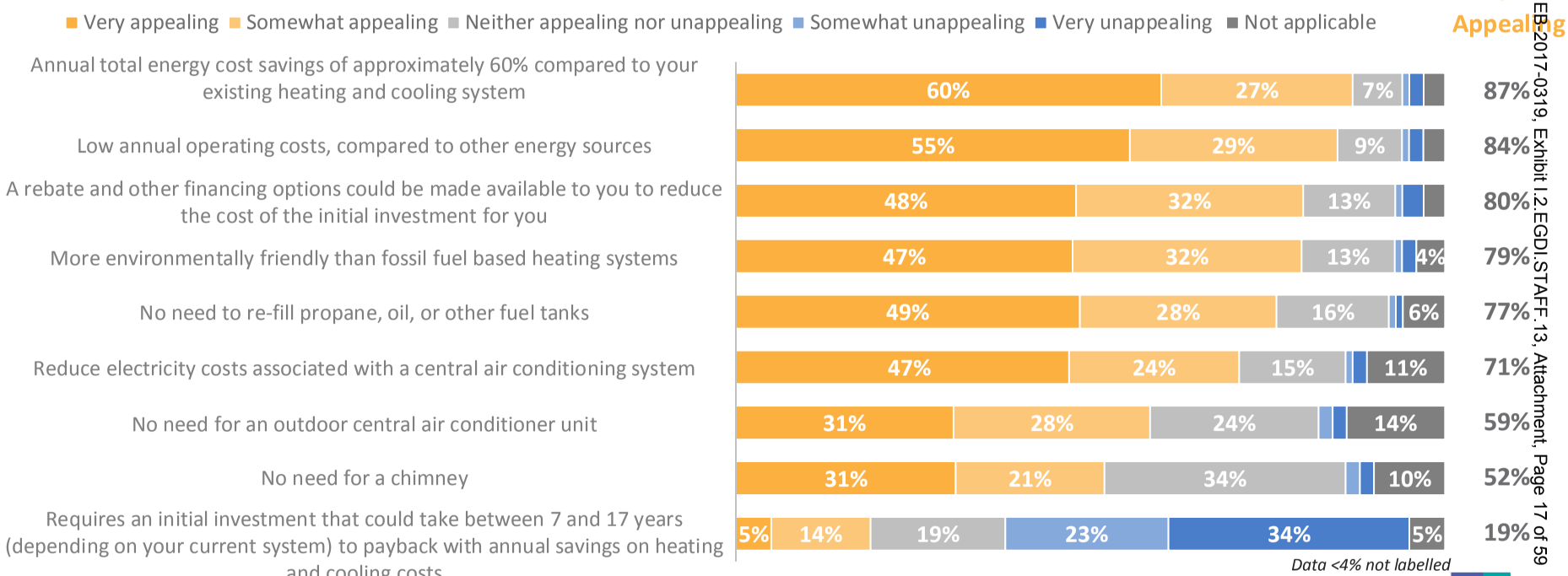


Mentions <3% not shown

Q13. What, if any kind of information would you like to know about geothermal heating and cooling systems?
Base: All Respondents (n=350)

Geothermal Appeal

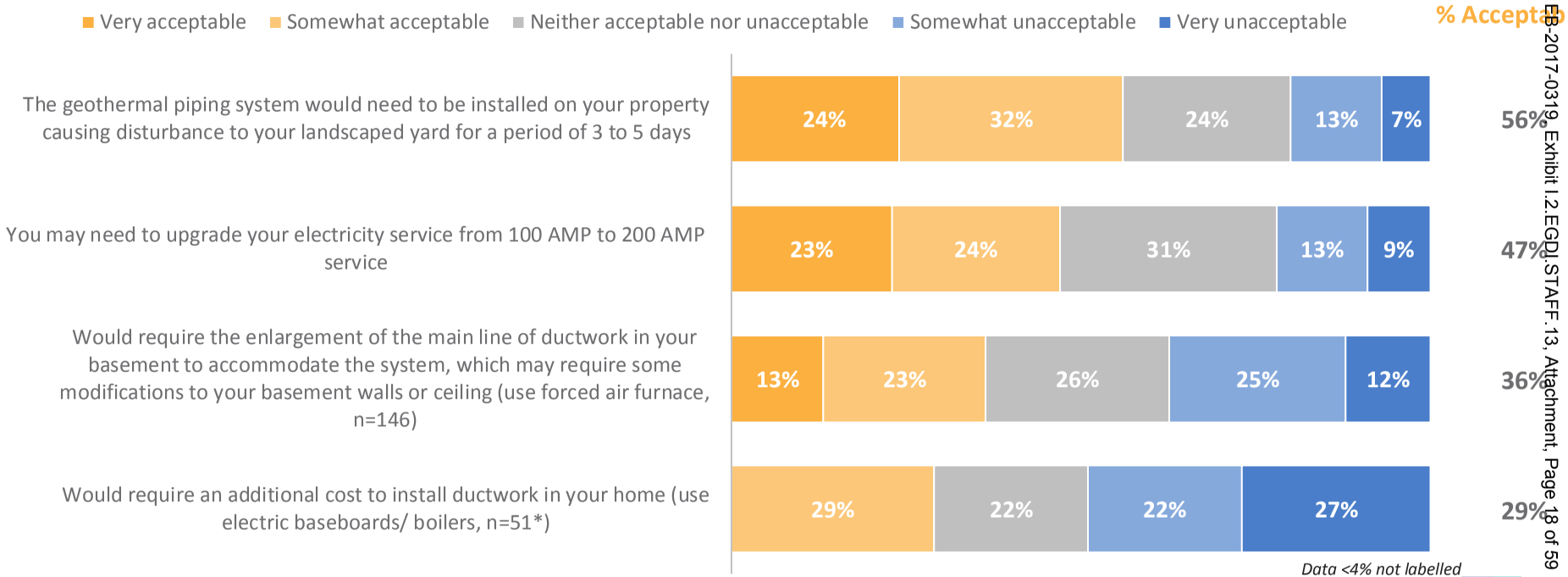
- Most homeowners find most characteristics of the geothermal system appealing for their household to consider replacing their existing system with geothermal, with the exception of knowing that the system would require an initial investment that takes between 7 and 17 years to pay back, indicating that this time period is too long for many homeowners to pay for the system.



Q14. Please indicate how appealing or unappealing the following characteristics of a geothermal system are for you and your household to consider replacing your existing heating, cooling and hot water heating systems with a geothermal system?
Base: All Respondents (n=350)

Acceptability of Geothermal System Requirements

- With the exception of the potential disturbances caused to a landscaped yard (for a period of 3-5 days), most homeowners do not feel that the requirements for installing a geothermal system are acceptable.

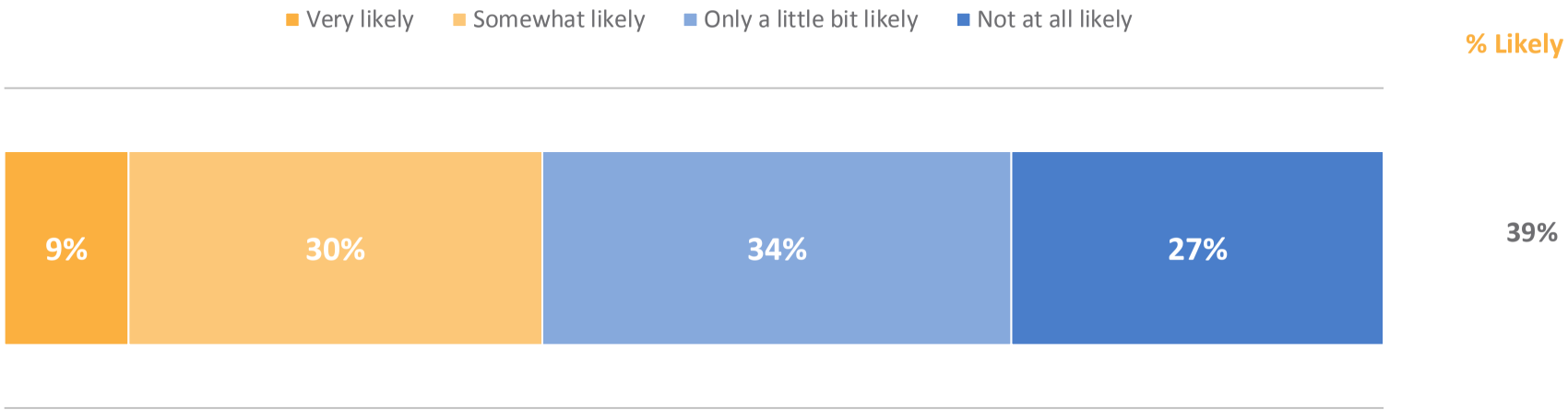


Q15. Please indicate how acceptable or unacceptable the following requirements for installing a geothermal system are for you and your household?
Base: All Respondents (n=350)

LIKELIHOOD TO INSTALL A GEOTHERMAL SYSTEM

Likelihood to Install Geothermal System

- After being informed that having a geothermal heating and cooling system could reduce annual energy costs by 60%, four in ten (39%) homeowners say they are likely to install a geothermal system, though only one in ten (9%) are 'very likely' with the remaining three in ten (30%) indicating they are only 'somewhat likely'. *Respondents were not informed of the specific costs involved with installing / converting to a geothermal system.*



Q16. How likely would you be to consider installing a geothermal system, knowing that an initial investment to change your current heating, cooling and hot water heating system could reduce your annual energy costs by approximately 60%?
Base: All Respondents (n=350)

Likelihood to Install Geothermal System – By Key Groups

- Those homeowners that use electricity, are under the age of 55, male, and are knowledgeable about geothermal technology are more likely to consider installing a geothermal system in their home.

	Total	Type of Energy Used to Heat Home			Respondent Age		Gender		Knowledge of Geothermal		Type of Equipment Used to Heat Home	
		Electricity	Propane	Oil	Under 55	55+	Male	Female	Very/ Somewhat Knowledgeable	Not Very Knowledgeable/ Never Heard of It	Electric Baseboards	Forced Air Furnace
Base	*350*	*82**	*152*	*116*	*79**	*271*	*131*	*219*	*150*	*200*	*40**	*299*
Very/Somewhat likely	39%	46%	32%	42%	49%	36%	48%	33%	47%	33%	42%	38%
Only a little bit/Not at all likely	61%	54%	68%	58%	51%	64%	52%	67%	53%	67%	58%	62%

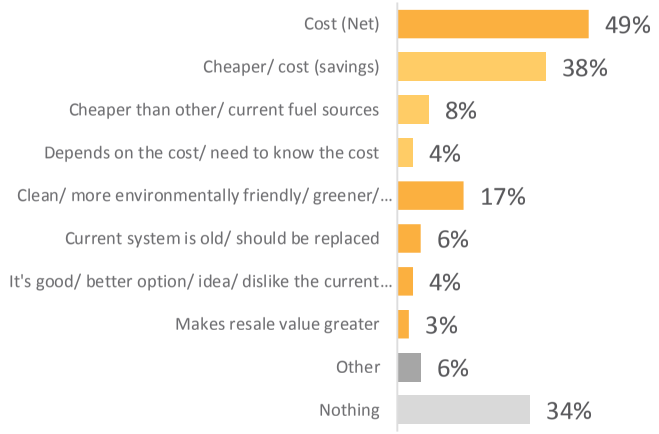
**Small base*
***Extremely small base*

Q16. How likely would you be to consider installing a geothermal system, knowing that an initial investment to change your current heating, cooling and hot water heating system could reduce your annual energy costs by approximately 60%?
Base: All Respondents (n=350)

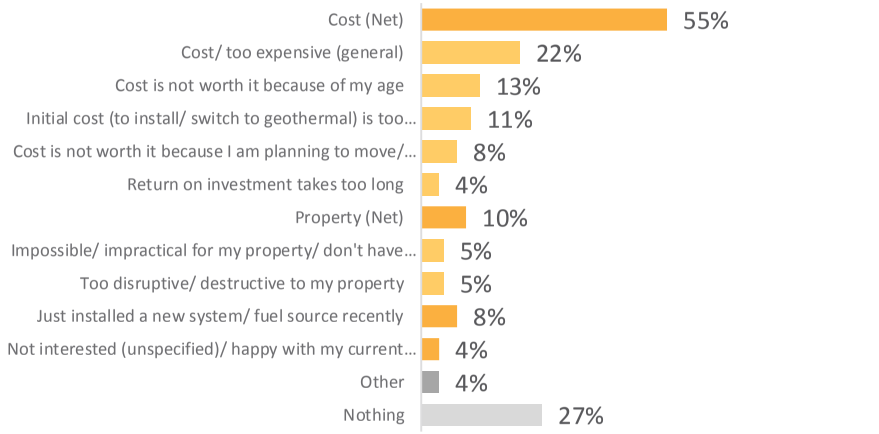
Reasons Would / Would Not Install Geothermal

- When asked why or why they would not install a geothermal system, a variety of responses are provided. Interestingly cost is cited as the main reason both for (49%) and against (55%) installing geothermal. Among those who are likely to install it, the highest proportion specifically mention that geothermal is cheaper / offers cost savings (38%) while around two in ten (17%) feel that it is more environmentally friendly. Conversely, of those who are unlikely to install it, the highest proportion of homeowners say they won't do it because it's too expensive (22%), or feel that the investment isn't worth it at their age (13%) or don't like the initial installation costs (11%).

REASONS WOULD INSTALL GEOTHERMAL



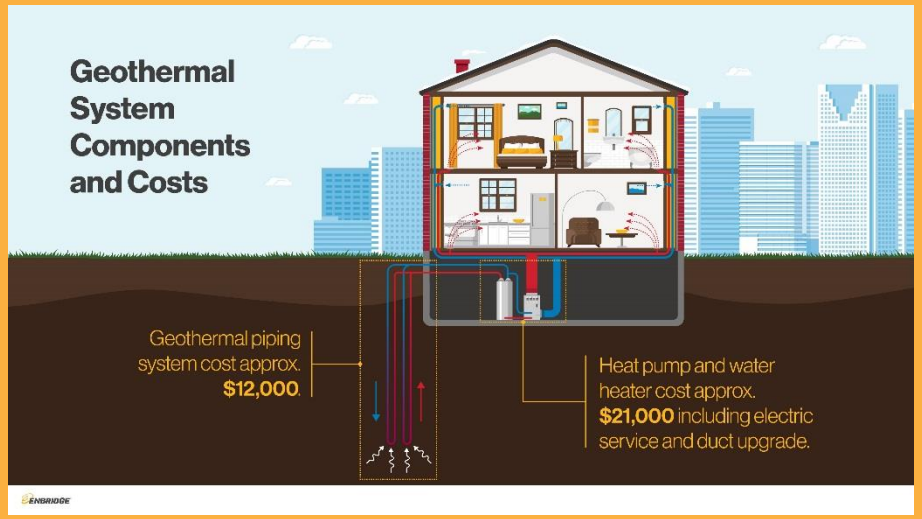
REASONS WOULD NOT INSTALL GEOTHERMAL



Q17.Why would you say that you would be likely to replace your existing heating, cooling, and hot water heating equipment with a geothermal system? *Mentions <3% not shown*
Base: Likely to consider installing a geothermal system (n=136)
Q18. Why would you say that you would be unlikely to replace your existing heating, cooling, and hot water heating equipment with a geothermal system?
Base: Unlikely to install a geothermal system (n=214)

Respondents were provided this description:

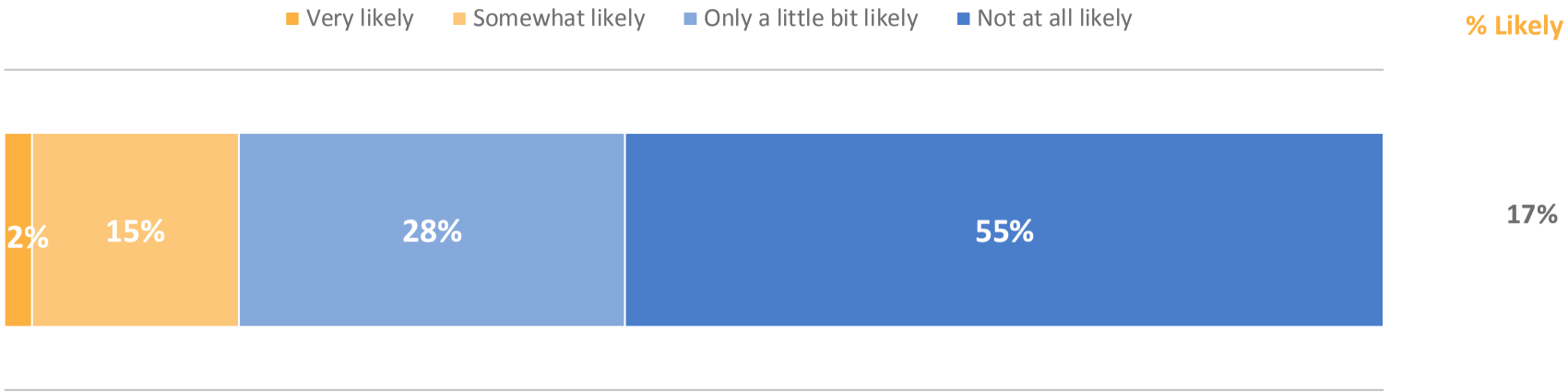
It is estimated that the cost for installing a geothermal heating, cooling and hot water system, including the equipment in your home ($21,000) and the geothermal piping system located in the ground outside your home ($12,000), is approximately $33,000 in total. The image below shows a breakdown of the costs.



Based on a heating system that uses [insert energy source from Q1], it is estimated that it would take approximately [insert if electricity: '14 years', if oil '13 years', if propane '17 years'] to pay for this initial investment with energy cost savings resulting from no longer using your existing equipment for heating and cooling. In addition, your monthly heating, cooling and hot water heating costs will be significantly lower for the life of the system.

Likelihood to Consider Geothermal: Overall Cost & Payback Period Provided

- After being informed of the base costs for installing a geothermal heating and cooling system and the payback period for various fuel types, only seventeen percent (17%) of homeowners say they would be likely to consider replacing their current heating, cooling, and hot water heating equipment with a geothermal system. Only 2% indicate that they would be 'very likely'.



Q19. Considering this, how likely would you be to consider replacing your existing heating, cooling, and hot water heating equipment with a geothermal system?
Base: All Respondents (n=350)

Likelihood to Consider Geothermal – By Key Groups (Cont.)

- Younger homeowners (under 55) and those who are at least somewhat knowledgeable about geothermal indicate that they are more likely to consider installing geothermal.
- Homeowners who use oil to heat their home or have more dated heating equipment (10+ years old) are generally more likely to consider geothermal.

	Total	Age of Heating Equipment			Type of Energy Used to Heat Home			Respondent Age		Knowledge of Geothermal		Type of Equipment Used to Heat Home	
		0-5 Years	6-10 Years	Over 10 Years	Electricity	Propane	Oil	Under 55	55+	Very/ Somewhat Knowledgeable	Not Very Knowledgeable / Never Heard of It	Electric Baseboards	Forced Air Furnace
Base	*350*	*129*	*78**	*143*	*82**	*152*	*116*	*79**	*271*	*150*	*200*	*40**	*299*
Very/Somewhat likely	16%	12%	15%	21%	16%	11%	23%	28%	13%	24%	10%	20%	16%
Only a little bit/Not at all likely	84%	88%	85%	79%	84%	89%	77%	72%	87%	76%	90%	80%	84%

**Small base*
***Extremely small base*

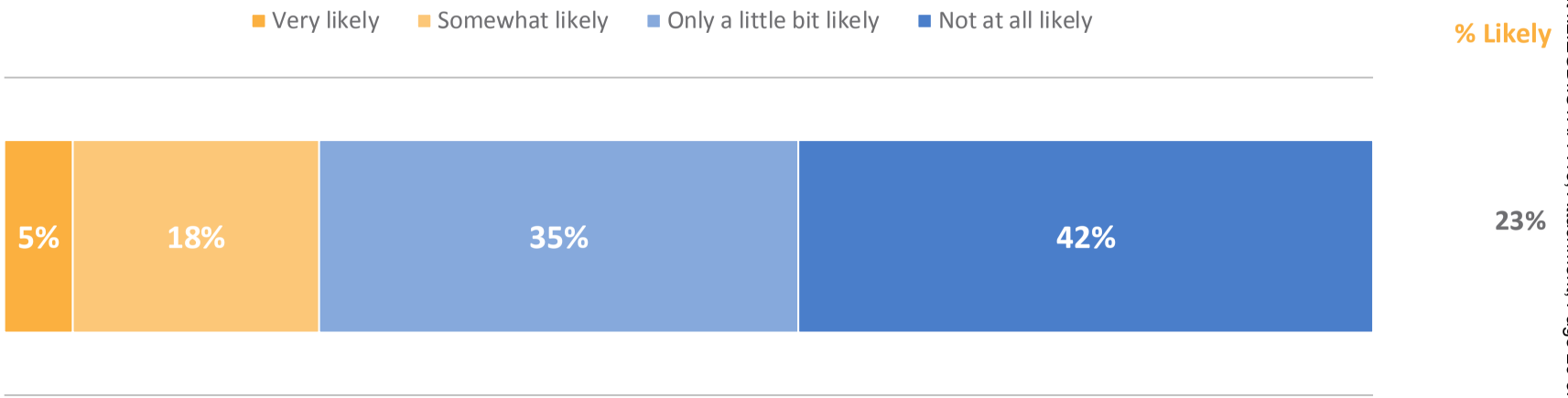
Q19. Considering this, how likely would you be to consider replacing your existing heating, cooling, and hot water heating equipment with a geothermal system?
Base: All Respondents (n=350)

Likelihood to Consider Geothermal: Gov't Subsidy Offered

- Only about one quarter (23%) of homeowners say they are likely (very/ somewhat likely) to consider replacing their existing heating, cooling, and hot water equipment system with a geothermal system if a $12k subsidy was offered by the Provincial Government. Only 5% would be 'very likely'.

Description Provided: In order to help homeowners cover the cost of the initial investment for installing a geothermal heating and cooling system, homeowners may be able to apply for a $12,000 subsidy from the Provincial Government for the heat pump portion of the system, which is inside your home.

This would reduce the cost of installing a geothermal heating and cooling system to approximately $21,000 from $33,000. Based on a heating system that uses [insert energy source from Q1], it is estimated that it would take approximately [insert if electricity: '9 years', if oil '8 years', if propane '11 years'] to pay for this initial investment with energy cost savings resulting from no longer using your existing heating, cooling and water heating equipment. In addition, your monthly heating, cooling and hot water heating costs will be significantly lower for the life of the system.



Q20. Considering this, how likely would you be to consider replacing your existing heating, cooling, and hot water heating equipment with a geothermal system if a subsidy of $12,000 was offered by government to reduce the cost of the heat pump?
Base: All Respondents (n=350)

Likelihood to Consider Geothermal if Gov't Subsidy Offered – By Key Groups

- When asked if they would consider replacing their current system with geothermal if a $12k subsidy was offered by the government, homeowners who are under 55 and those who are at least somewhat knowledgeable about geothermal are more likely to say they would do this.
- Homeowners who use oil to heat their home are generally more likely to consider replacing their current system with geothermal if a $12k subsidy was offered by the government.

	Total	Age of Heating Equipment			Type of Energy Used to Heat Home			Respondent Age		Knowledge of Geothermal		Type of Equipment Used to Heat Home	
		0-5 Years	6-10 Years	Over 10 Years	Electricity	Propane	Oil	Under 55	55+	Very/ Somewhat Knowledgeable	Not Very Knowledgeable / Never Heard of It	Electric Baseboards	Forced Air Furnace
Base	*350*	*129*	*78**	*143*	*82**	*152*	*116*	*79**	*271*	*150*	*200*	*40**	*299*
Very/Somewhat likely	23%	19%	22%	27%	24%	17%	29%	34%	20%	31%	16%	28%	22%
Only a little bit/Not at all likely	77%	81%	78%	73%	76%	83%	71%	66%	80%	69%	84%	72%	78%

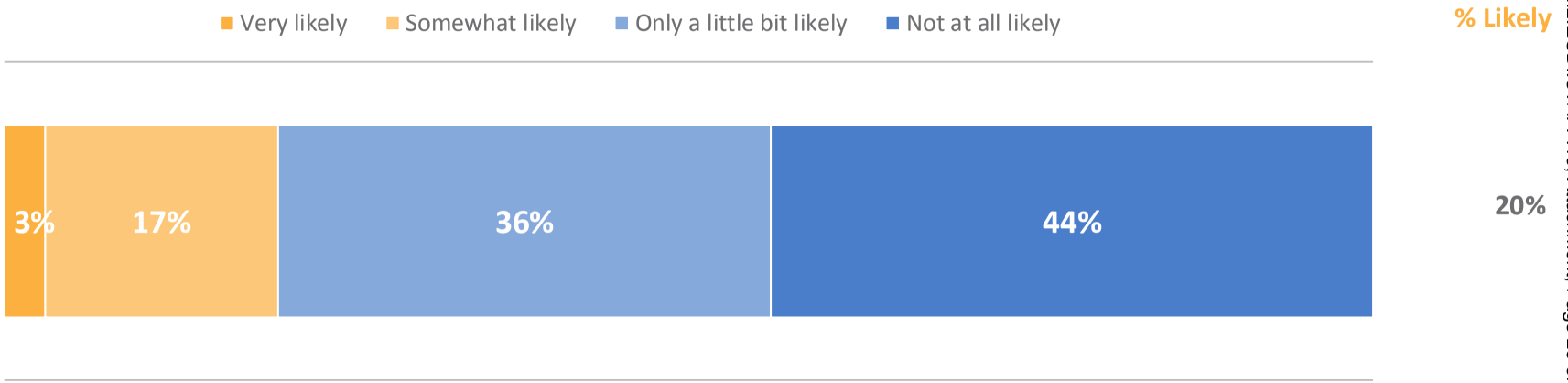
*Small base
**Extremely small base

Q20. Considering this, how likely would you be to consider replacing your existing heating, cooling, and hot water heating equipment with a geothermal system if a subsidy of $12,000 was offered by government to reduce the cost of the heat pump?
Base: All Respondents (n=350)

Likelihood to Consider Geothermal if Rental Service Option Provided

- Only two in ten (20%) indicate they would be likely to consider replacing their existing heating, cooling, and hot water equipment with a geothermal system if Enbridge was to provide a rental service option for the geothermal piping loop, in addition to the $12k government subsidy that would be offered by the Provincial Government. Only 3% of homeowners are 'very likely'

Description Provided: After applying the government subsidy of $12,000 the cost of a new geothermal system would be $21,000. In order to eliminate more of this up-front cost, Enbridge could own and maintain the geothermal piping component of the system (which is outside your home) for a monthly rental service charge of $75-$100 to be paid by you for 30 years. The remaining cost of $9,000 for the heat pump would now be approximately equivalent to the cost to replace your existing heating and cooling system. In addition, your monthly heating and cooling costs will be still lower for the life of the system.



Q21. Considering this, how likely would you be to replace your existing heating, cooling, and hot water heating equipment with a geothermal system if Enbridge was to provide a rental service option for the geothermal piping system in addition to the $12,000 government subsidy that would be offered by government to reduce the cost of the heat pump?
Base: All Respondents (n=350)

Likelihood to Consider Geothermal if Rental Service Option Provided – By Key Groups

- Homeowners with at least some knowledge of geothermal are more likely to consider replacing their existing heating, cooling, and hot water heating equipment with a geothermal system if Enbridge was to provide a rental service option in addition to the $12k government subsidy.

	Total	Age of Heating Equipment			Type of Energy Used to Heat Home			Respondent Age		Knowledge of Geothermal		Type of Equipment Used to Heat Home	
		0-5 Years	6-10 Years	Over 10 Years	Electricity	Propane	Oil	Under 55	55+	Very/ Somewhat Knowledgeable	Not Very Knowledgeable / Never Heard of It	Electric Baseboards	Forced Air Furnace
Base	*350*	*129*	*78**	*143*	*82**	*152*	*116*	*79**	*271*	*150*	*200*	*40**	*299*
Very/Somewhat likely	20%	18%	15%	24%	24%	15%	22%	24%	18%	26%	15%	28%	18%
Only a little bit/Not at all likely	80%	82%	85%	76%	76%	85%	78%	76%	82%	74%	85%	72%	82%

Small base
Extremely small base

Q21. Considering this, how likely would you be to replace your existing heating, cooling, and hot water heating equipment with a geothermal system if Enbridge was to provide a rental service option for the geothermal piping system in addition to the $12,000 government subsidy that would be offered by government to reduce the cost of the heat pump?
Base: All Respondents (n=350)

Likelihood to Consider Geothermal if Rental Service Option Provided – By Key Groups (Continued)

- Homeowners with a more favourable impression of Enbridge are more likely to consider replacing their existing system with geothermal if a rental service was provided by Enbridge in addition to the $12k government subsidy.

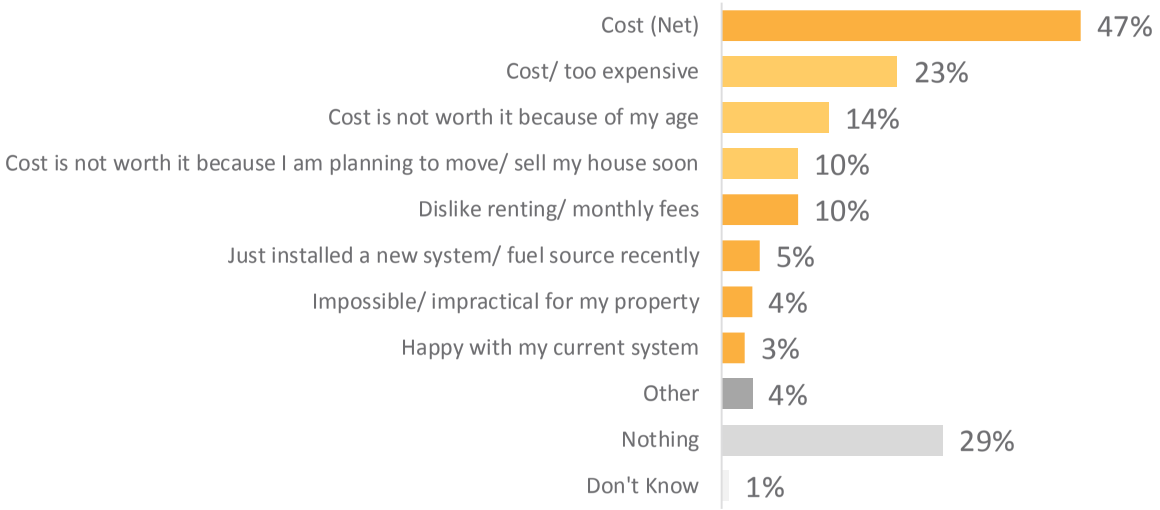
	Total	Knowledge of Enbridge			Impressions of Enbridge		
		Know it very well/ a Fair Amount	Just a little bit	Know almost nothing/ Never heard of it	Positive	Negative	Don't Know
Base	*350*	*150*	*117*	*83**	*171*	*46**	*133*
Very/Somewhat likely	20%	24%	21%	11%	26%	13%	14%
Only a little bit/Not at all likely	80%	76%	79%	89%	74%	87%	86%

Small base
Extremely small base

Q21. Considering this, how likely would you be to replace your existing heating, cooling, and hot water heating equipment with a geothermal system if Enbridge was to provide a rental service option for the geothermal piping system in addition to the $12,000 government subsidy that would be offered by government to reduce the cost of the heat pump?
Base: All Respondents (n=350)

Reasons Unlikely to Install Geothermal if Rental Service Provided

- Of those who are unlikely to install a geothermal system if a rental service option were provided in addition to the $12k subsidy, the highest proportion say they wouldn't do it because of the cost (47%), specifically, that it is still too expensive (23%) or that the cost is not worth it because of their age (14%) or because they are planning to move (10%). Around one in ten (10%) say they simply don't like renting or monthly fees (10%). Three in ten (29%) provide no response.



Mentions <3% not shown

Q22. Why would you be unlikely to consider replacing your existing heating, cooling, and hot water heating system with a geothermal system if you were able to pay a monthly rental service fee for the geothermal piping system?
Base: Unlikely to install geothermal system if rental service option provided (n=281)

Reasons Unlikely to Install Geothermal if Rental Service Provided – By Key Groups

- Homeowners who are 55 years of age or older are more likely to be deterred from geothermal because of the cost – specifically the cost not being worth it due to their age whereas younger respondents are more likely to be deterred from geothermal due to the monthly rental fees. Homeowners with modern heating equipment (0-5 years) are more likely to say they wouldn't install geothermal because they recently installed a new system.

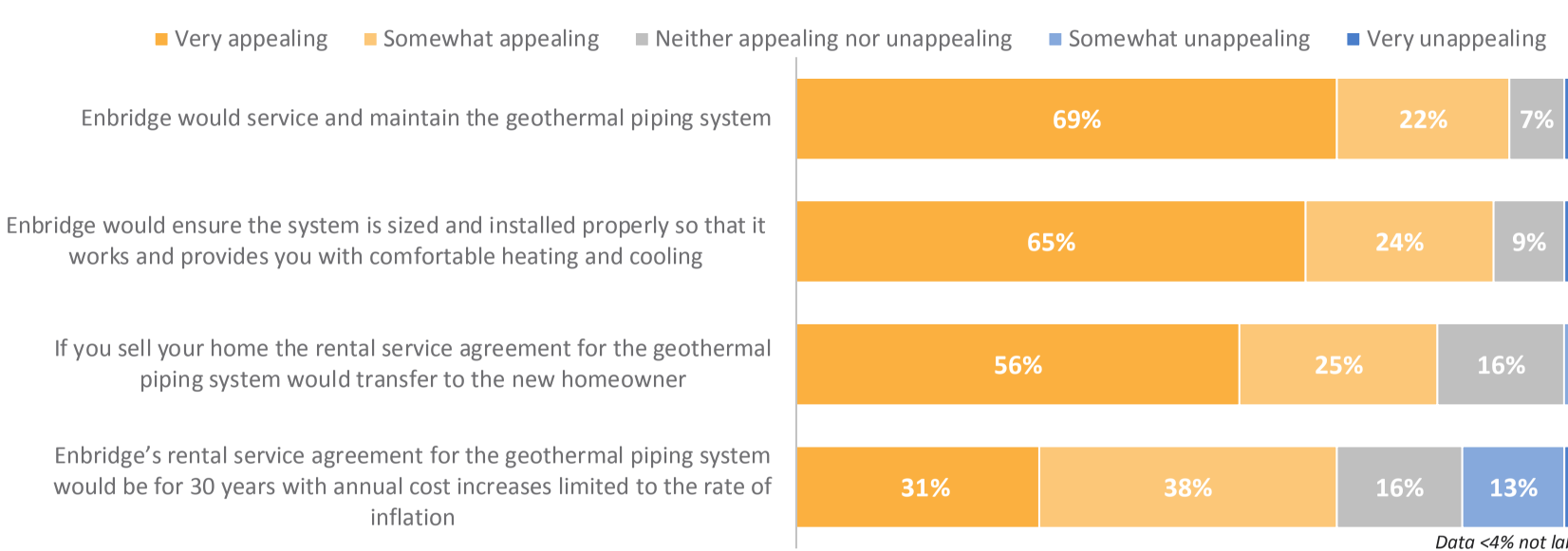
	Total	Age of Heating Equipment			Respondent Age	
		0-5 Years	6-10 Years	Over 10 Years	Under 55	55+
Base	*350*	*129*	*78**	*143*	*79**	*271*
Cost (net)	47%	39%	45%	56%	32%	51%
Cost/ too expensive	23%	21%	18%	28%	18%	24%
Cost is not worth it because of my age	14%	10%	15%	17%	2%	17%
Cost is not worth it because I am planning to move/ sell my house soon	10%	6%	17%	9%	12%	9%
Dislike renting/ monthly fees	10%	14%	11%	6%	22%	7%
Just installed a new system/ fuel source recently	5%	13%	2%	-	8%	5%
Impossible/ impractical for my property	4%	5%	5%	2%	-	5%
Happy with my current system	3%	2%	2%	5%	3%	3%
Other	4%	6%	2%	4%	3%	4%
Nothing	29%	31%	38%	24%	35%	29%
Don't Know	1%	1%	-	3%	2%	1%

Mentions <3% not shown

Q22. Why would you be unlikely to consider replacing your existing heating, cooling, and hot water heating system with a geothermal system if you were able to pay a monthly rental service fee for the geothermal piping system?
Base: Unlikely to install geothermal system if rental service option provided (n=281)

Appeal of Rental Service Agreement

- The vast majority of those who are likely to install a geothermal system if a subsidy and rental service option are provided find all characteristics of the geothermal pipe system rental agreement to be at least somewhat appealing. At nine in ten, the highest proportion find it appealing that Enbridge would service and maintain the system (91%) or that it would ensure the system is sized and installed properly (89%) while closer to eight in ten (82%) think it's appealing that their agreement would transfer to the new homeowner while seven in ten (69%) say it's appealing that the agreement would be for 30 years with annual cost increases limited to the rate of inflation.

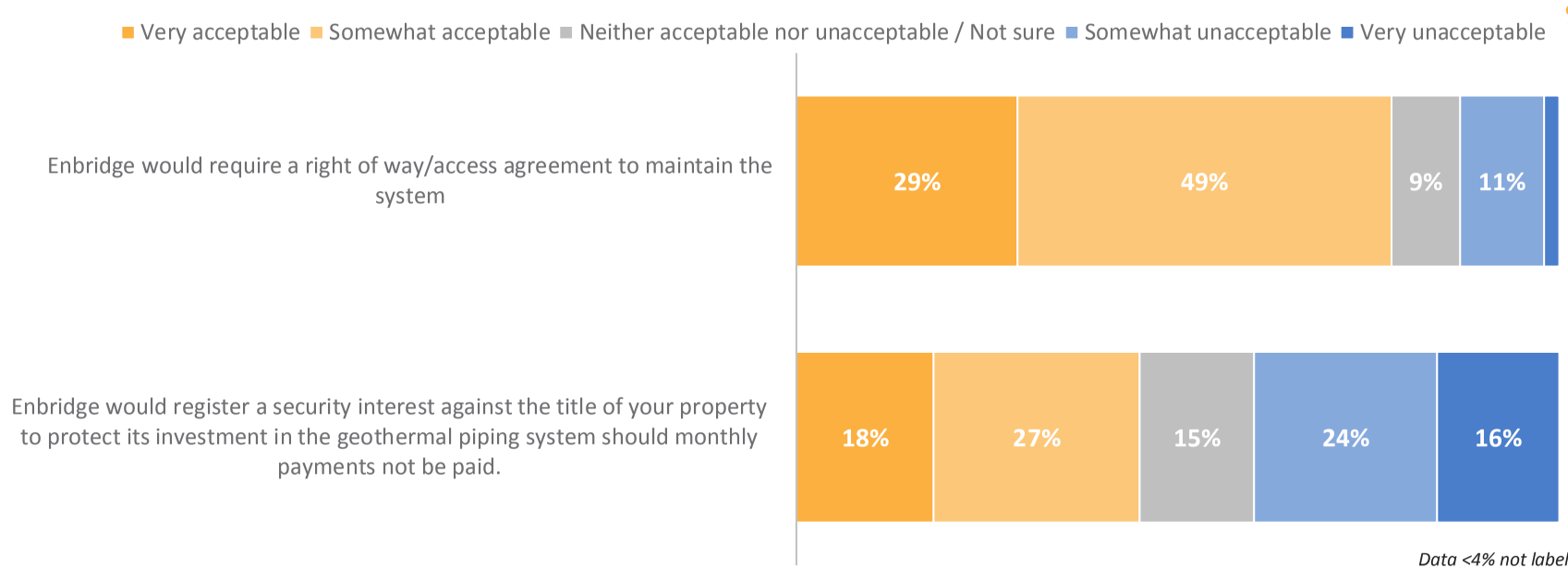


Q23. Please indicate how appealing or unappealing the following characteristics of the geothermal pipe system rental service agreement would be to you.
Base: Very/ somewhat likely to install geothermal system if subsidy offered and if rental service option provided (n=55*)

*Small base
**Extremely small base

Acceptability of Rental Service Agreement

- Among those who are likely to install a geothermal system if a subsidy and rental service option are provided, a large majority (78%) feel that a right of way/ access agreement to maintain the system is reasonable whereas less than half (45%) think it's acceptable that Enbridge would register a security interest against the title of the renter's property should the monthly payments not be made.

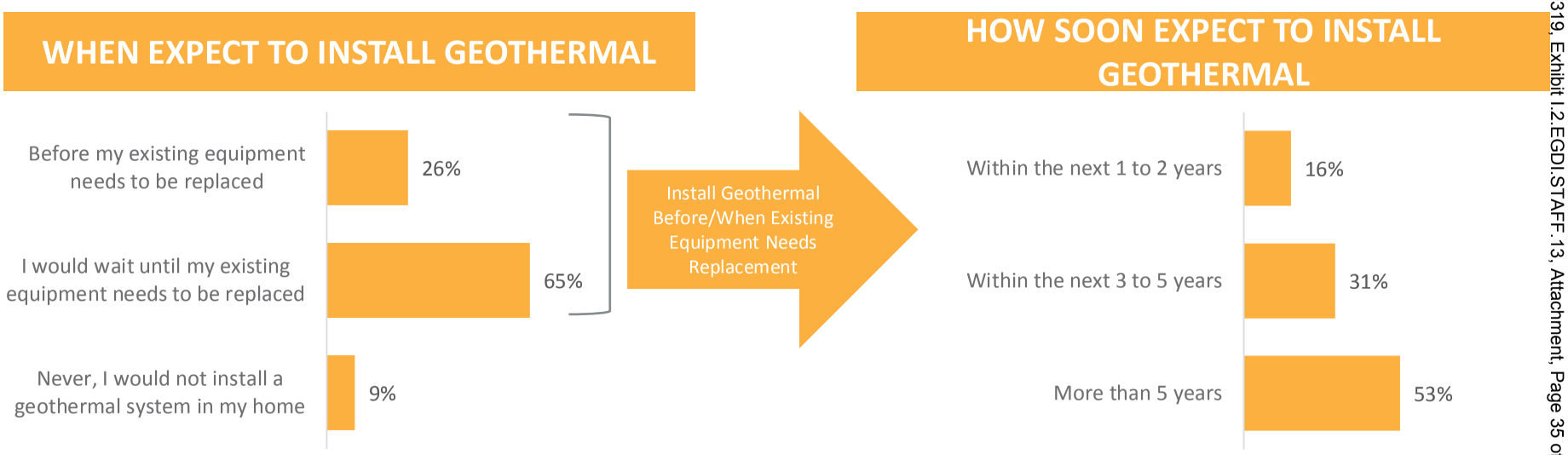


Q24. Please indicate how acceptable or unacceptable the following characteristics of the geothermal piping system rental service agreement would be to you.
Base: Very/ somewhat likely to install geothermal system if subsidy offered and if rental service option provided (n=55)

*Small base
**Extremely small base

Timing of Geothermal System Installation

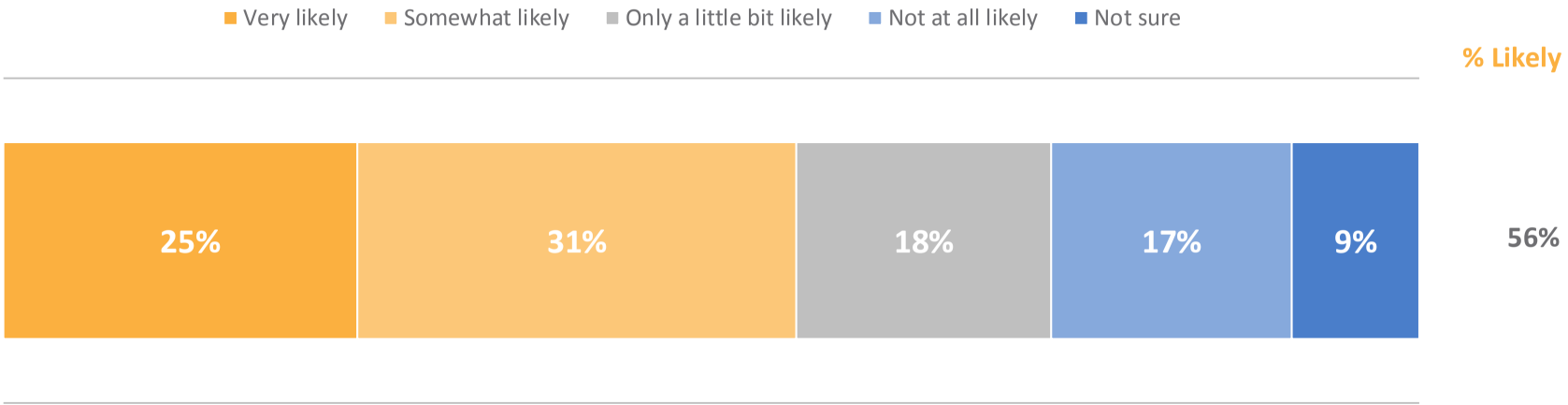
- Two thirds (65%) of those who are likely to install a geothermal system say they would do so only when their existing equipment needs replacing compared to one quarter (26%) who would do it before and one in ten (9%) who would never do it in their current home.
- Of those who plan to install a geothermal system before or when their existing equipment needs replacement, over half (53%) plan to wait more than 5 years, three in ten (31%) within the next 3-5 years, and sixteen percent (16%) within the next 1-2 years.



Q26. When would you expect to install a geothermal heating and cooling system?
Base: Very/ somewhat likely to install geothermal system in general or if subsidy offered or if rental service option provided (n=102)
Q27. How soon would you expect to install a geothermal heating and cooling system?
Base: Would install geothermal system before existing equipment needs to be replaced or would wait until existing equipment needs to be replaced (n=93)

Likelihood to Install Geothermal System if Equal Cost

- More than half (56%) of homeowners say they would be likely (very/ somewhat likely) to switch to a geothermal system when their existing system is at the end of its useful life and if the cost was identical to the cost of replacement of their current system.



Q28. If the cost of a new geothermal system was identical to the replacement cost of your existing furnace and air conditioner, how likely would you be to switch to a geothermal system when your existing system is at the end of its useful life?
Base: All Respondents (n=350)

Likelihood to Install Geothermal System if Equal Cost – By Key Groups

- Homeowners that use a forced air furnace to heat their home are most likely to say they would install a geothermal system if the cost is identical to the replacement cost of their existing system.

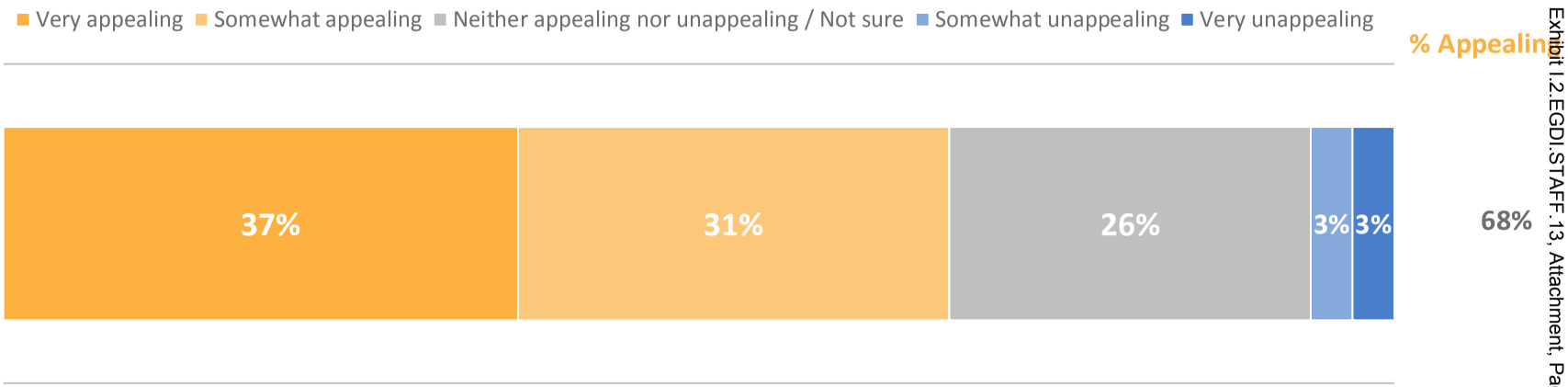
	Total	Type of Energy Used to Heat Home			Type of Heating Equipment Used	
		Electricity	Propane	Oil	Electric Baseboards	Forced Air Furnace
Base	*350*	*82**	*152*	*116*	*40**	*299*
Very/Somewhat likely	57%	51%	58%	59%	35%	59%
Only a little bit/Not at all likely	35%	35%	35%	34%	42%	34%

Q28. If the cost of a new geothermal system was identical to the replacement cost of your existing furnace and air conditioner, how likely would you be to switch to a geothermal system when your existing system is at the end of its useful life?
Base: All Respondents (n=350)

*Small base
**Extremely small base

Energy Independence Appeal

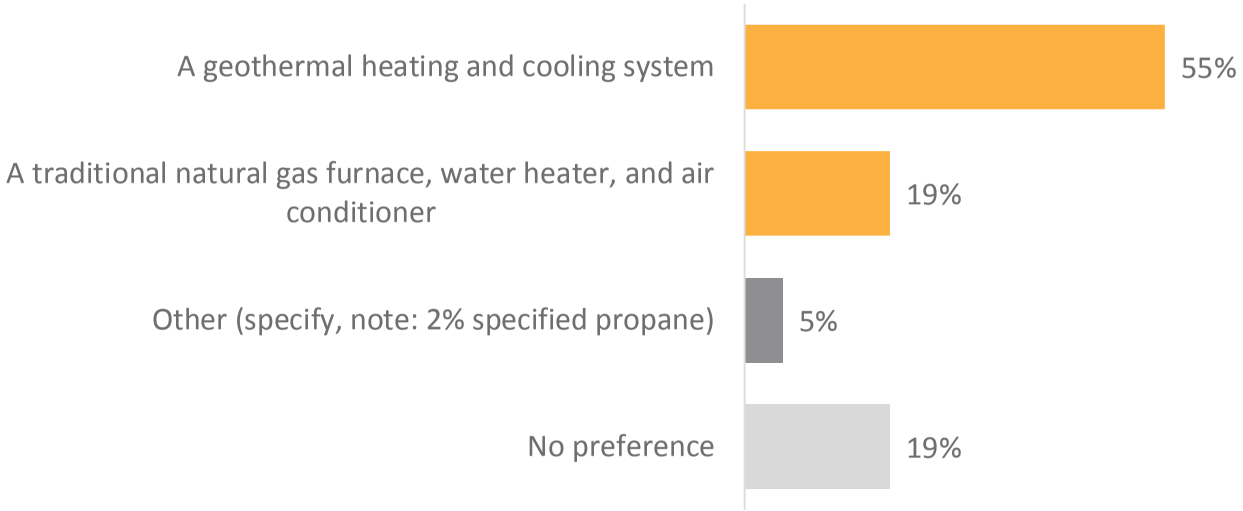
- At over two thirds (68%) a large majority view energy independence as appealing with around one quarter (26%) expressing a somewhat neutral opinion. Very few (6%) see energy independence as an unappealing way to avoid future increases in fossil fuel and electricity prices.



Q32. The geothermal system can help to eliminate or reduce the use of fossil fuel and electricity to heat and cool your home making your home more energy independent or 'off the grid'. Using solar energy to power a geothermal system would further increase your energy independence. How appealing is energy independence as a way to avoid future increases in fossil fuel and electricity prices to you?
Base: All Respondents (n=350)

Heating & Cooling System Preferences if Purchasing New Home

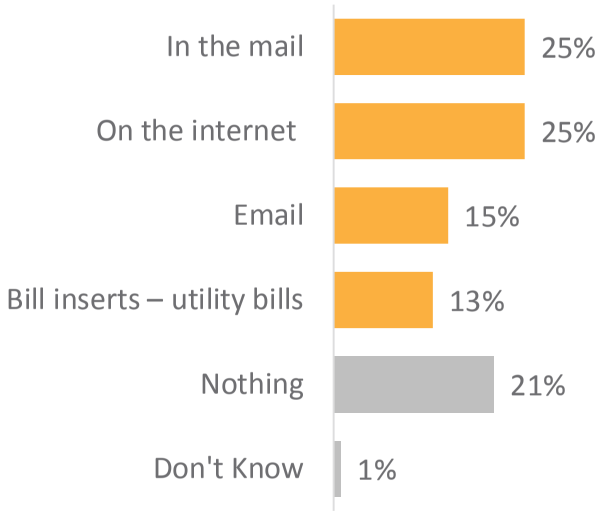
- At well over half (55%), most indicate they would prefer to install a geothermal heating and cooling system if they were to build a new home. Two in ten (19%) either have no preference or would prefer to install a traditional natural gas furnace, water heater, and air conditioner. Only two percent (2%) say they would prefer to install propane.



Q30. If you were purchasing a newly built home, which of the following heating, cooling, and hot water heating systems would you prefer?
Base: All Respondents (n=350)

Preferred Method for Communication

- One quarter (25%) of homeowners would prefer to receive more information about installing a geothermal heating and cooling system in the mail or on the internet, with fifteen percent (15%) indicating a specific preference for receiving this by email and thirteen percent (13%) via bill inserts.



Q31. How, if at all, would you like to receive more information about installing a geothermal heating and cooling system?
Base: All Respondents (n=350)

Preferred Method for Communication – By Key Groups

- Younger homeowners (under 55) are more likely to indicate a preference for receiving communications via email. Homeowners who use electric baseboards to heat their homes are more likely to prefer receiving communications in the mail.

	Total	Respondent Age		Type of Equipment Used to Heat Home	
		Under 55	55+	Electric Baseboards	Forced Air Furnace
Base	*350*	*79**	*271*	*40**	*299*
In the mail	25%	27%	24%	40%	23%
On the Internet	25%	25%	25%	22%	24%
Email	15%	23%	13%	12%	16%
Bill inserts – utility bills	13%	10%	13%	10%	13%
Nothing	21%	13%	24%	12%	23%
Don't Know	1%	1%	-	-	1%

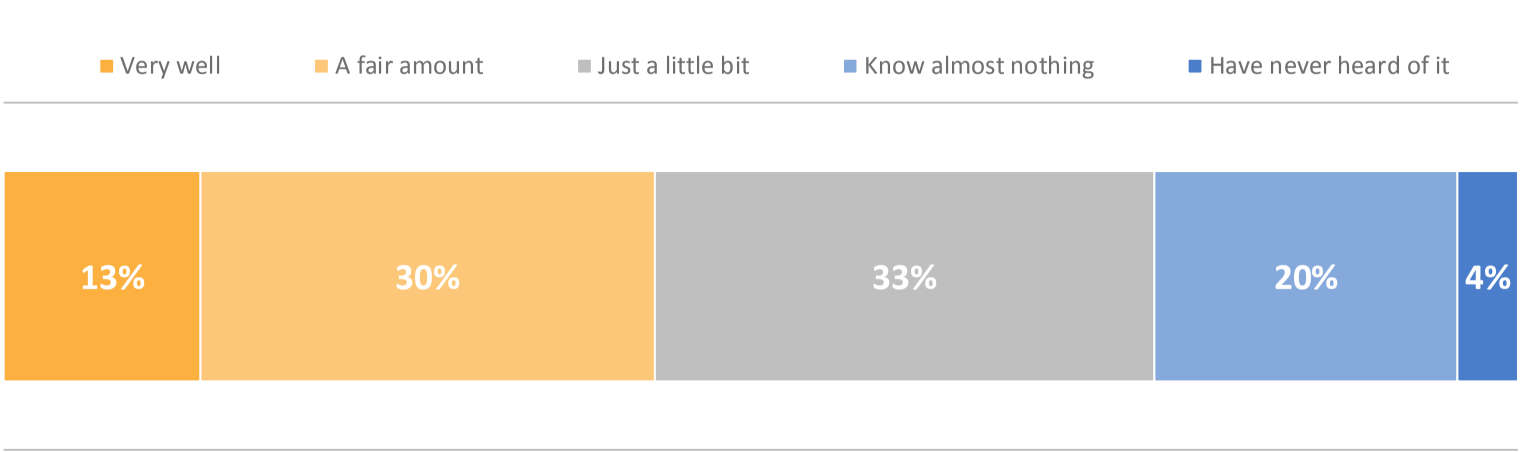
**Small base*
***Extremely small base*

Q31. How, if at all, would you like to receive more information about installing a geothermal heating and cooling system?
Base: All Respondents (n=350)

AWARENESS OF AND IMPACT OF ENBRIDGE BRAND

Awareness of Enbridge Gas Distribution

- More than four in ten (43%) homeowners claim to have at least a fair amount of knowledge of Enbridge Gas Distribution, of which only thirteen percent (13%) claim to know the company 'very well', with three in ten (30%) indicating they know it 'a fair amount'. One third (33%) feel they know 'just a little bit' about the company while two in ten (20%) say they 'know almost nothing'. Very few (4%), however, say they have never heard of Enbridge Gas Distribution.



Q9. How well do you feel you know a company called Enbridge Gas Distribution, a distributor of natural gas to homes and businesses in parts of Ontario?
Base: All Respondents (n=350)

Awareness of Enbridge Gas Distribution – By Key Groups

- Homeowners who claim to be very/ somewhat knowledgeable about geothermal, are likely to seek information about geothermal, or are likely to replace their existing system with geothermal are more likely to indicate awareness of Enbridge Gas Distribution.

% Know Enbridge Very Well / A Fair Amount

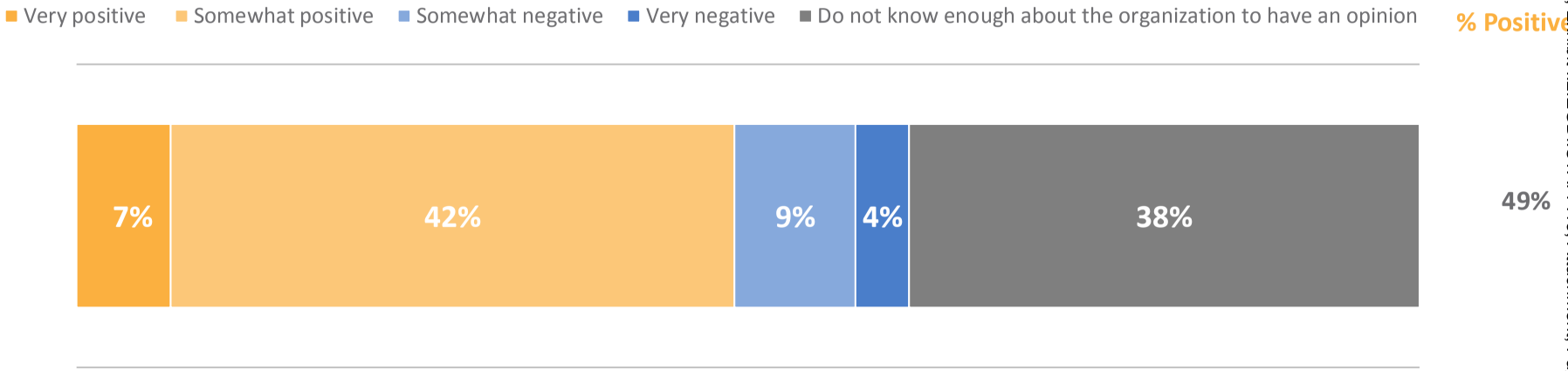
	Total	Knowledge of Geothermal		Likelihood to Seek Information about Geothermal		Likelihood to Replace Existing System with Geothermal	
		Very/Somewhat	Not Very/Never heard of	Likely	Unlikely	Likely	Unlikely
Base	*350*	*150*	*200*	*125*	*225*	*57**	*293*
Very well/A fair amount	43%	62%	28%	51%	38%	56%	40%
Just a little bit	33%	25%	40%	30%	35%	26%	35%
Know almost nothing/Have never heard of it	24%	13%	32%	18%	27%	18%	25%

**Small base*
***Extremely small base*

Q9. How well do you feel you know a company called Enbridge Gas Distribution, a distributor of natural gas to homes and businesses in parts of Ontario?
Base: All Respondents (n=350)

Impression of Enbridge Gas Distribution

- Half (49%) of homeowners have a positive (very/ somewhat positive) impression of Enbridge Gas Distribution while around four in ten (38%) feel like they don't know enough to have an opinion and thirteen percent (13%) express a negative (very/ somewhat negative) opinion.



Q10. Based upon what you know about Enbridge Gas Distribution would you say that you have a positive or negative impression of the organization? If you do not know enough about the organization, please say so.
Base: All Respondents (n=350)

Impression of Enbridge Gas Distribution – By Key Groups

- Those who hold a positive impression of Enbridge Gas Distribution are more likely to know at least a fair amount about Enbridge and indicate at least some knowledge of geothermal. This group is also more likely to replace their existing system with geothermal or seek more information about geothermal in the future.

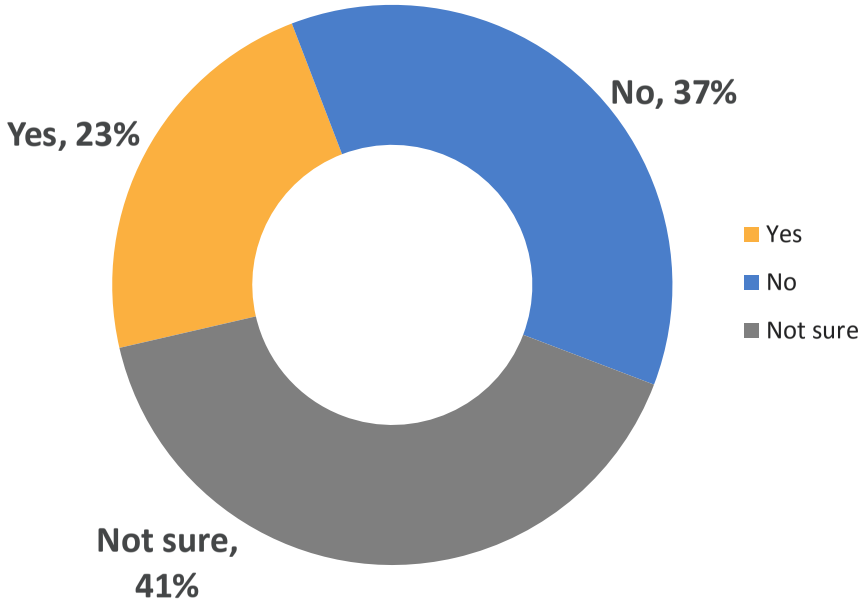
	Total	Knowledge of Enbridge			Knowledge of Geothermal		Likelihood to Seek Information about Geothermal		Likelihood to Replace Existing System with Geothermal	
		Very well/ Fair amount	Just a little bit	Know almost nothing/ Never heard of	Very/ Somewhat	Not Very/Never heard of	Likely	Unlikely	Likely	Unlikely
Base	*350*	*150*	*117*	*83**	*150*	*200*	*125*	*225*	*57**	*293*
Very/Somewhat Positive	49%	78%	38%	11%	61%	40%	62%	42%	61%	46%
Somewhat/Very Negative	13%	17%	12%	7%	11%	14%	11%	14%	14%	13%
Don't know enough to have opinion	38%	5%	50%	82%	27%	46%	27%	44%	25%	41%

**Small base*
***Extremely small base*

Q10. Based upon what you know about Enbridge Gas Distribution would you say that you have a positive or negative impression of the organization? If you do not know enough about the organization, please say so.
Base: All Respondents (n=350)

Peace of Mind

- Around one quarter (23%) feel that the Enbridge name provides them with the peace of mind that would make them more likely to consider installing geothermal. However, at four in ten (41%), the highest proportion say they are not sure if the Enbridge name provides them with peace of mind with almost as many (37%) claiming it doesn't.



Q25. Does the Enbridge name provide you with peace of mind that would make you more likely to consider installing a geothermal system?
Base: All Respondents (n=350)

Peace of Mind – By Key Groups

- Homeowners who have at least some knowledge of geothermal or Enbridge are more likely to indicate that the Enbridge name provides them with the peace of mind that would make them consider installing a geothermal system. Homeowners who say they are likely to seek information about geothermal, replace their existing system with geothermal, or install geothermal are also more likely to say this.

	Total	Knowledge of Enbridge			Knowledge of Geothermal		Likelihood to Seek Information about Geothermal		Likely to Install Geothermal		Likelihood to Replace Existing System with Geothermal	
		Very well/ Fair amount	Just a little bit	Know almost nothing/ Never heard of	Very/ Somewhat	Not Very/Never heard of	Likely	Unlikely	Likely	Unlikely	Likely	Unlikely
Base	*350*	*150*	*117*	*83**	*150*	*200*	*125*	*225*	*136*	*214*	*57**	*293*
Yes	23%	33%	19%	8%	29%	18%	43%	11%	38%	13%	44%	18%
No	37%	37%	42%	29%	41%	34%	19%	46%	23%	45%	21%	40%
Not sure	41%	30%	39%	63%	30%	49%	38%	43%	39%	42%	35%	42%

Q25. Does the Enbridge name provide you with peace of mind that would make you more likely to consider installing a geothermal system?
Base: All Respondents (n=350)

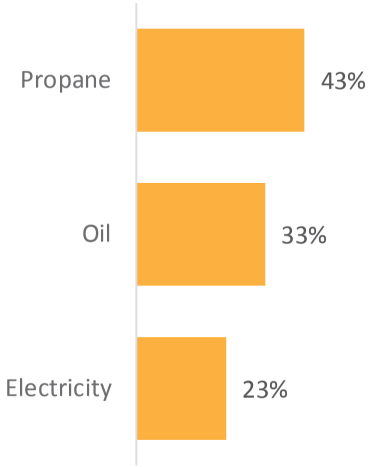
*Small base
**Extremely small base

APPENDIX: RESPONDENT PROFILE

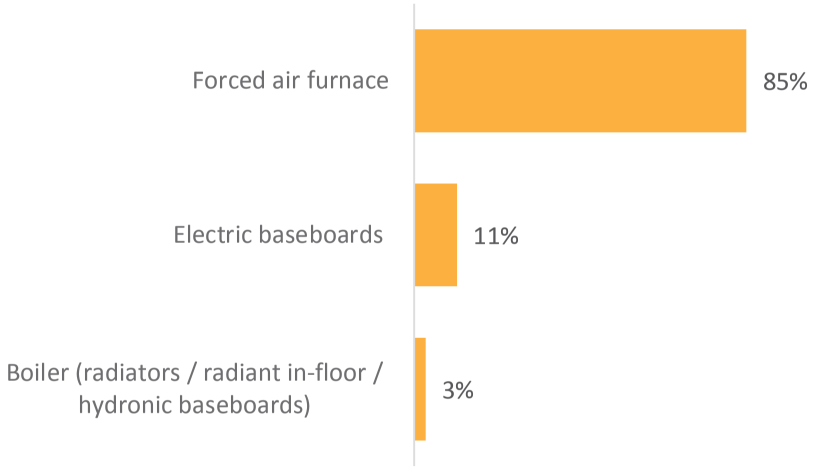
Energy & Equipment Used to Heat Home

- At over four in ten (43%), the highest proportion of homeowners use propane to heat their home, followed by oil (33%), and electricity (23%). In terms of the type of equipment used, the vast majority (85%) say they have a forced air furnace followed by one in ten (11%) who use electric baseboards. Only three percent (3%) use a boiler (radiators/ radiant-in-floor/ hydronic baseboards).

TYPE OF ENERGY USED TO HEAT HOME



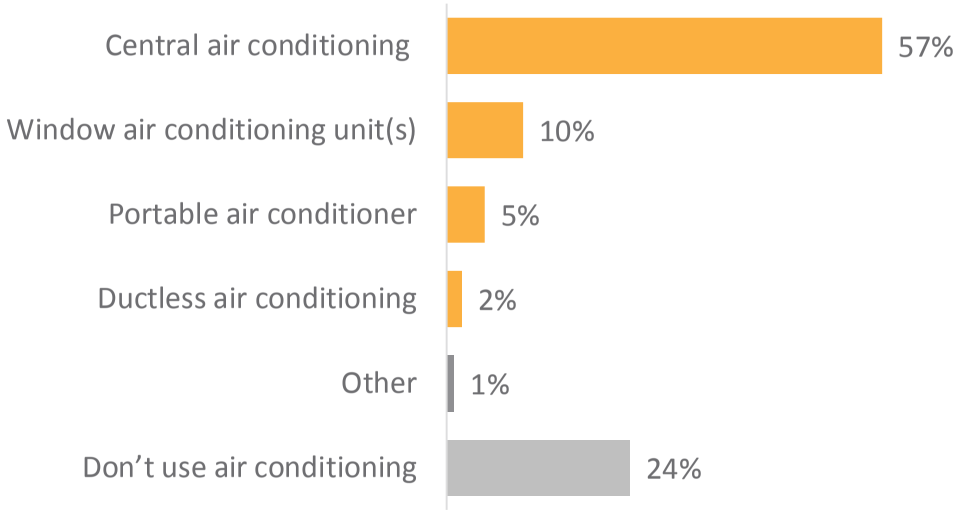
TYPE OF EQUIPMENT USED TO HEAT HOME



Q1.What type of energy do you use to primarily heat your residence? / Q2. What type of equipment do you use to primarily heat your residence?
Base: All Respondents (n=350)

Types of Air Conditioning Used

- At nearly six in ten (57%), most homeowners say they have central air conditioning while one in ten (10%) have a window air conditioning unit and even fewer, portable (5%) or ductless (2%) air conditioning. One quarter (24%) of homeowners indicate that they do not use air conditioning.

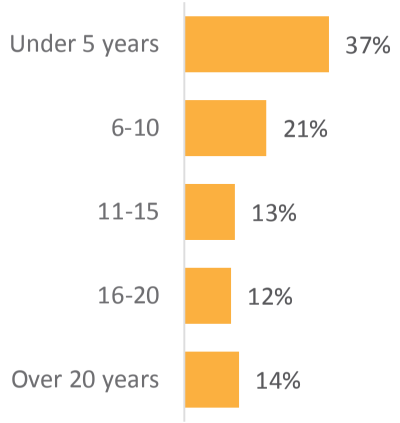


Q4. Which, if any, of the following types of air conditioning do you use?
Base: All Respondents (n=350)

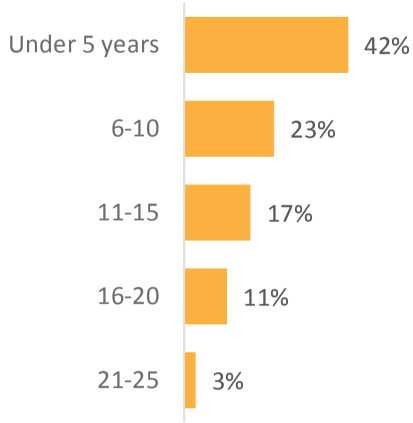
Age of Primary Heating & Air Conditioning Equipment

- At around four in ten, the highest proportion of homeowners indicate that the age of both their primary heating (37%) and air conditioning equipment (42%) is 5 years or less.

AGE OF PRIMARY HEATING EQUIPMENT



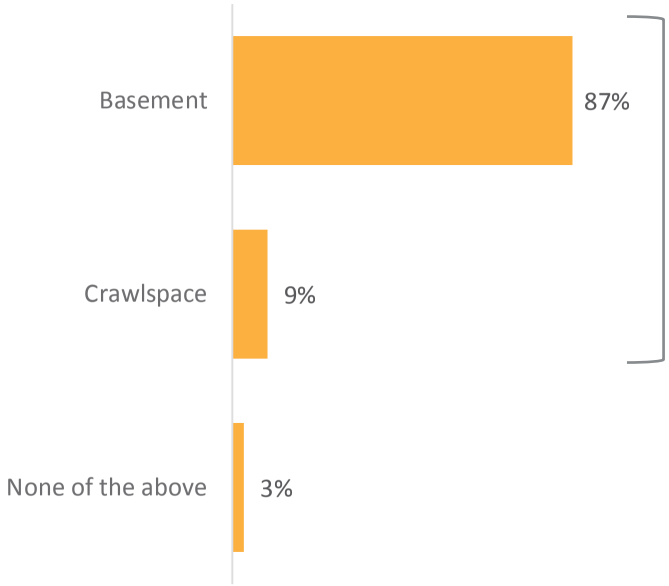
AGE OF AIR CONDITIONING EQUIPMENT

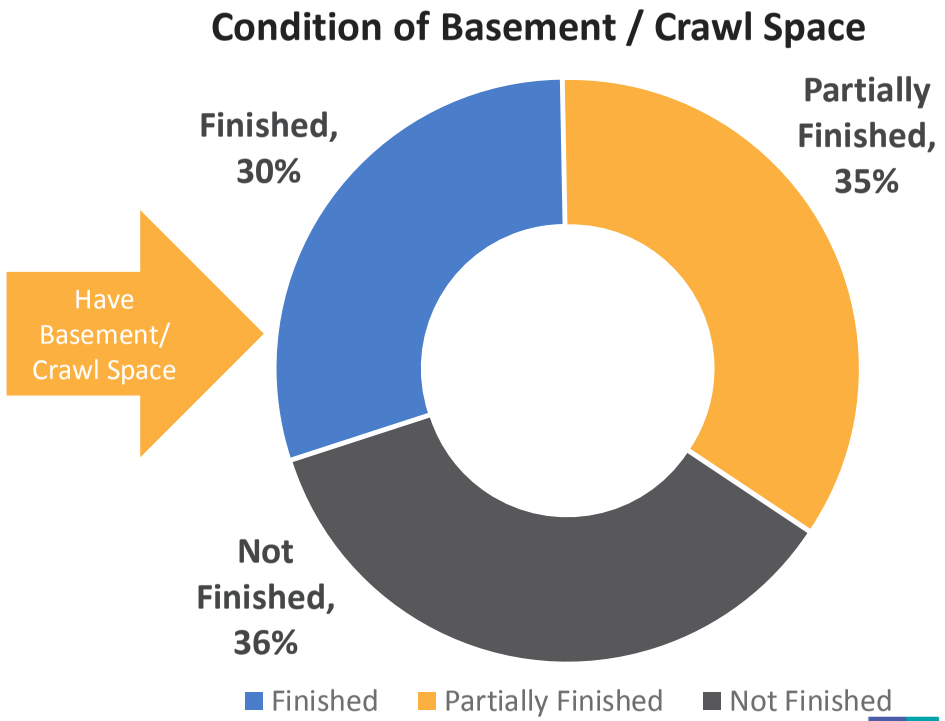


Q3. Approximately how old is this primary heating equipment?
Base: All Respondents (n=350)
Q5. Approximately how old is your air conditioning equipment?
Base: Use Air Conditioning (n=267)

Basement / Crawlspace

- Virtually all (96%) homeowners have a basement or crawlspace in their home.
- Among those that do have a basement or crawlspace, most say it is either in finished (30%) or partially finished (35%) condition.

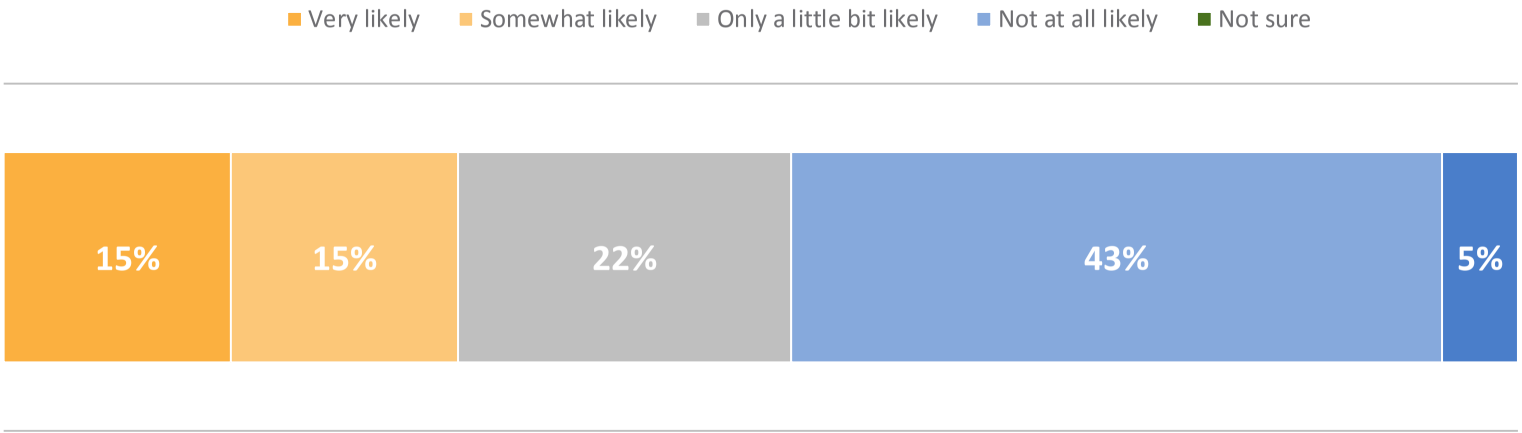




Q6. Do you have a basement or crawlspace in your home?
Base: All Respondents (n=350)
Q7. Which of the following best describes the condition of the [insert: basement or crawl space] in your home?
Base: Have a basement or crawlspace (n=338)

Likelihood to Sell Home

- Three in ten (30%) homeowners say they are likely to sell their home within the next 5 years.

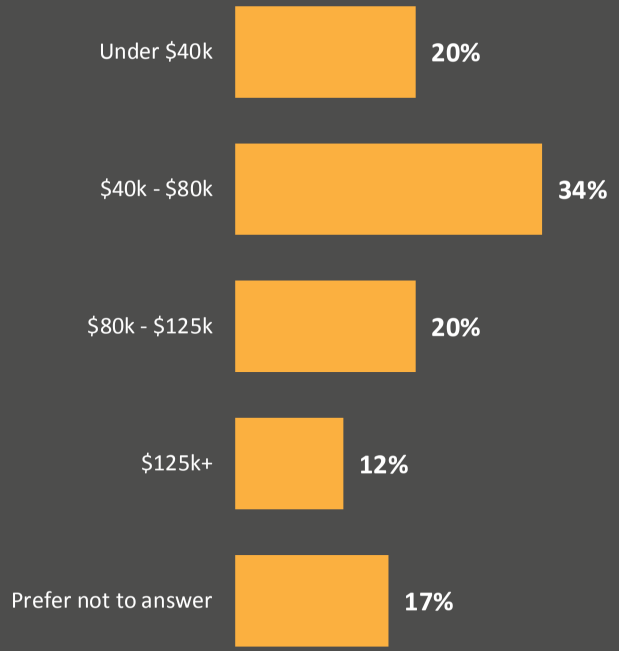


Q29. How likely are you to sell your home in the next 5 years?
Base: All Respondents (n=350)

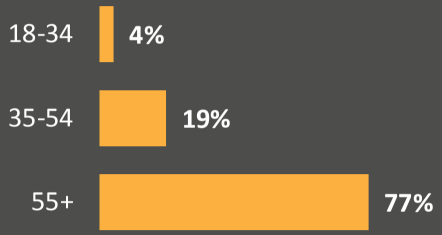
DEMOGRAPHICS

DEMOGRAPHICS

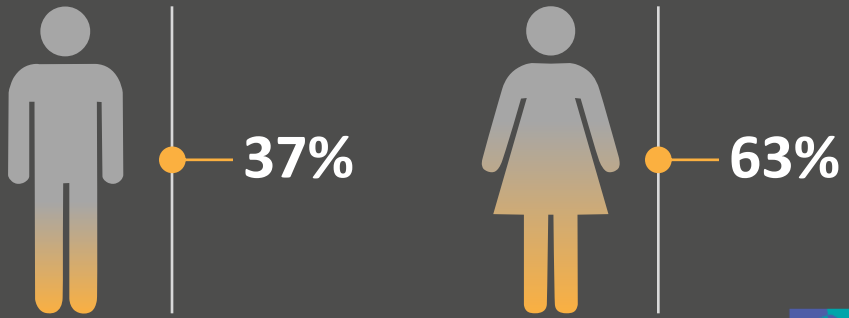
Household Income



Age

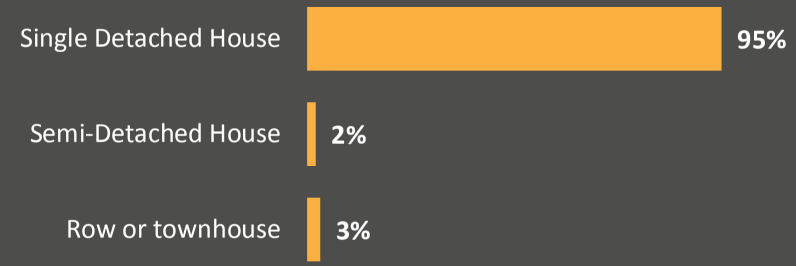


Gender

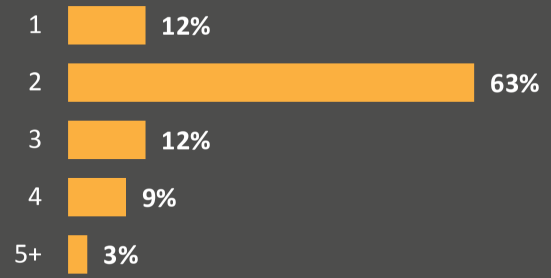


DEMOGRAPHICS (Continued)

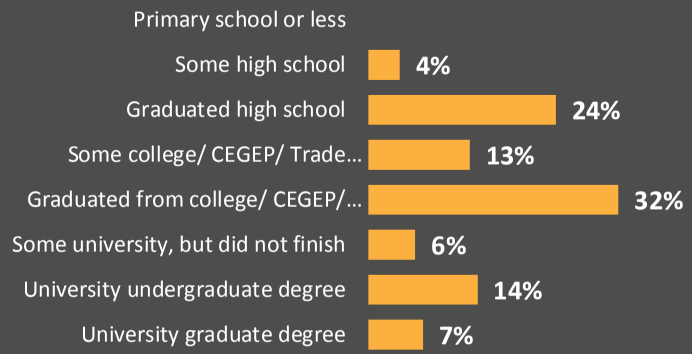
Type of home



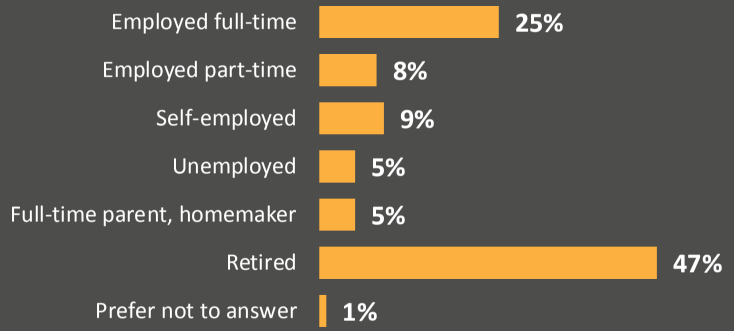
Number of people in household



Education



Employment Status



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Geothermal Research 2017

ENBRIDGE CONTACT

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STAFF INTERROGATORY #14

INTERROGATORY

Issue 2 – Cost Consequences

Topic: Geothermal Energy Service (GES) Program – Calculation of Service Fees

Ref: Exhibit B / Tab 1 / Schedule 1 / pp. 27-28, #81 and #82

Preamble:
Enbridge Gas indicates that the estimated capital costs for the installation of the geothermal loops are based on unit costs for drilling and trenching. Further, the estimated capital costs will also include construction management, commissioning and quality assurance with contingencies based on geographical and geological construction uncertainties.

Enbridge Gas also indicates the operating and maintenance expenses for the program includes periodic inspection and maintenance, customer care and billing cost, overhead and management costs plus a one-time setup and development costs.

Questions:

a) Please outline the unit costs for:
   i) A Geothermal loop
   ii) Drilling
   iii) Trenching
   iv) Construction
   v) Commissioning
   vi) Quality Assurance
   vii) O&M expense (which would include customer care, billing costs, overhead, periodic inspection and maintenance, etc.)

b) For the unit costs outlined in a) above, please discuss how these costs were determined and provide all supporting documentation including data, assumptions and analysis.

c) For the unit costs outlined in a) above, please explain how these costs would change with different geography and geology in Ontario.

d) Please explain whether the unit costs outlined in a) above, would change if Enbridge Gas installed a geothermal loop in an existing gas heated home vs. a new construction.

e) Please describe the one-time setup and development costs (e.g., the amount and why this is needed)? Please explain how this cost will be recovered?

f) For the O&M expenses outlined in a), please provide the costs for each of the following:
   - Periodic inspection and maintenance
   - Customer case
   - Overhead and management
   - Billing

g) Please explain whether Enbridge Gas has to modify its billing system to incorporate its GES Program? If so, what are the costs associated with this modification and how will this cost be recovered?

RESPONSE

a) i) The installation costs of loop for new construction is estimated to be $3,000/Tonne of loop installed, and for retrofit market $3,200/Tonne of loop installed
   ii) The unit cost above includes drilling
   iii) The unit cost above includes trenching
   iv) The unit cost above includes construction. There are also additional non-unit capital costs related to construction, in relation to construction supervision, inspection, customer connection, and work management during the construction period.
   v) See iv) above. In addition, the commissioning of the heat pump is performed by the heat pump contractor, and would be part of the heat pump installation contracted by the homeowner. However, Enbridge would have inspectors quality assuring the construction and commissioning process.
   vi) See responses to iv) and v) above
   viii) The O&M costs are a blend of unit costs and allocated costs. Unit costs include periodic inspection and maintenance, billing, customer care, and potential loop replacement. Allocated costs include finance and accounting, supply chain, administration, engineering and management costs. As more customers are added, the unit costs of O&M associated with the Geothermal Energy Service program will decrease as fixed costs are allocated across more customers.

b) The capital costs were estimated based on the following assumptions:
   - Majority of the customers would require a vertical loop
   - Costs from the Company's geothermal pilot indicated a loop cost per tonne of approximately $2,850 per tonne.
   - Upon conversations with OGA and the drilling contractors, it was confirmed that the cost to drill vertical loops vary based on geography and can range from $2,500 to $4,500.
   - The Company is of the view that a $3,000 per tonne of installed loop would constitute a reasonable estimate that will cover most geological conditions and also embed any cost savings from volumes.
   - For retrofit construction, this cost was increased to $3,200 per tonne of installed loop to account for the one off nature of the installations and mobilization and demobilization of drilling equipment for single homes.
   - The indirect costs of construction include construction supervision and inspectors who would quality assure installations and witness commissioning as well as work management costs and customer connection costs.

   The O&M Costs were determined by building a bottom up analysis of expected types of expenses. Some costs such as billing and customer care are unit costs per customer. Shared services such as finance, supply chain and accounts payables are based on estimated hours that will be billed to this line of business. The overhead and management expenses are provided in part (e) below.

   The Company installs underground pipe and works with developers and contractors as part of its existing business. While building the DCF model for this proposed program, the Company has endeavored to use the same methodologies and estimated costs on a fully allocated basis. The Company sees the deployment and management of this program to be no different from an operational perspective to its current business.

c) The Company has not undertaken an analysis on how these unit costs would vary between geographies.

d) See response to part a i) and b). O&M expenses are not expected to change between a new construction and retrofit construction home.

e) The one time development costs assumed are:
   - Training customer care: $30,000
   - Training inspectors: $30,000
   - Set up of financial systems, Work Management Systems, Record keeping etc: $100,000
   - Customer information systems: $200,000

   The service fee proposed for approval includes recovery of these costs.

f) Enbridge's forecast O&M costs for the noted categories are set out below (all costs are based on fully allocated costs). All of these costs are included in the DCF model and will be recovered in the customer fees.

   - **Periodic inspection and maintenance:** $15/year per customer as well as $100 one time per customer for potential loop replacements.
   - **Customer care:** $10/year/customer for first 2 years, $5/year for years beyond 2nd year (It is expected that with a new technology and service, customers would require more customer care for the first 2 years).
   - **Overhead and management:** The yearly overhead and management costs are approximately $970,000 per year for the first three years, increasing to $1,200,000 per year for the next seven years (as customer additions increase). After the first 10 years of the 40 year model, the costs drops to approximately $370,000 per year for the management of the 18,000 customers included in the model.
   - **Billing:** $32/year per customer.

g) In order to properly manage the program from a customer care perspective, the Company will need to make a small number of enhancements to add a new product/service within the existing CIS billing system. Changes like this require development and proper testing to ensure there are no other impacts. These enhancements will enable regular billing and typical account management activities like move in/out and collections both in the call centre and via the website. Total cost is estimated at $200,000, as noted in the response to part e) above.

STAFF INTERROGATORY #15

INTERROGATORY

Issue 2 – Cost Consequences

Topic: Geothermal Energy Service (GES) Program – Calculation of Service Fees

Ref: Exhibit B / Tab 1 / Schedule 1 / p. 28, #83
Exhibit B / Tab 1 / Schedule 1 / Appendix 11 and Appendix 12

Preamble:
Enbridge Gas indicates that its service is $25.20 per tonne and in Appendix 12 outlines its costs assumptions.

Questions:

a) Does Enbridge Gas intend to enter into a service agreement with the residential customer? Please explain. If yes, please provide the service agreement.
   i) What is expected length of the contract?

b) Please explain whether the $25.20 per tonne is $25.20 t CO2e per month.
   i) Does Enbridge Gas intend to charge the customer $100.80 per month for the geothermal loops ($25.20 per tonne * 4 [number of tonnes per customer])? Please explain.
   ii) Please explain whether the service fees ($25.20 per tonne) are fixed for the length of the customer's contract? If not, why not?

c) Line 21, Appendix 12, states that the revenue per tonne per month is $25.30. Please explain why this is different that the loop service fee of $25.20 per tonne.

d) Line 4, Appendix 12, states the number of tonnes per customer is assumed to be 4. Please explain how this number was calculated. Please provide all supporting documentation including data, assumptions and analysis.
   i) Does the number of tonnes per customer depend on the housing stock (e.g., existing vs new construction) and geography/geology? Please explain.
      1. If so, please provide the number of tonnes per customer for: 1) an existing home by the potential different geography and geology and 2) a new construction by the potential different geography and geology.

e) Please explain whether Enbridge considered calculating a service fee for each of the different types of housing stock per geography/geology? If not, why not?

f) Please explain whether Enbridge Gas included in its DCF Analysis (Appendix 11) any of the GreenOn funding from the provincial government.

   i) If the customer/Enbridge Gas does not receive GreenOn funding for its GES Program, please explain how this will impact Enbridge Gas' feasibility study?

g) Please provide the description of property/rate class used for CCA rate.

h) Please provide discounted cash flow analysis and complete Table 5 below by changing each of the following assumptions in the analysis and calculate accumulated NPV and PI for the 40 year forecast horizon (assuming the service fee stays at the same level as the base case).
   i) Discount rate (i.e. Cost of debt, ROE, Capital structure)
   ii) Capital investment
   iii) O&M expense

Table 5. Scenario Analysis for Geothermal Energy Services			
Scenario	Service Fee	Accumulated NPV at Year 40	PI at Year 40
Base Case	$25.30 per tonne per month	$ 17,027,767	1.102
Scenario 1(a) Base case cost of debt + 50 bps	$25.30 per tonne per month		
Scenario 1(b) Base case cost of debt + 100 bps	$25.30 per tonne per month		
Scenario 1(c) Base case ROE + 100 bps	$25.30 per tonne per month		
Scenario 1(d) Base case ROE + 300 bps	$25.30 per tonne per month		
Scenario 1(e) 50/50 D/E ratio	$25.30 per tonne per month		
Scenario 1(f) 35/65 D/E ratio	$25.30 per tonne per month		
Scenario 2 Base case capital investment ($237,148,543)+10% increase	$25.30 per tonne per month		
Scenario 3 Base case O&M expense +10% increase (Year 1 to Year 40)	$25.30 per tonne per month		

RESPONSE

a) i) There will not be a written service agreement with Geothermal Energy Service customers who receive service from the regulated utility. As is the case with natural gas customers, the Geothermal Energy Service customers will be subject to the Company's Conditions of Service, which may have to be updated.

b) i) The Company wishes to clarify that the proposed service fee is $25.07 per tonne of loop capacity installed not $25.20 per tonne of CO_2. The Company will file updated evidence to reflect the change. Please refer to the covering letter related to the filing of interrogatory responses in this proceeding.

The monthly charge will depend on the size of the loop installed and will vary by size and vintage of homes. The monthly charge for a customer who require a 4 tonne loop capacity would be $25.07 X 4 = $100.28.

ii) The service fee will be fixed until such time as the Board approves a new service fee. Where there are material changes in the costs associated with the Geothermal Energy Service program, Enbridge will bring forward evidence to the Board to propose any increase or decrease to the service fee. This will provide a transparent service fee based on costs and protect customers as this market develops.

c) Please see the response to b) above.

d) Based on current building designs and heating requirements of new homes, it is estimated that the average home size lies between 1800-2400 sq. ft. with average peak heating requirements of <50,000btu/h. Using this data, the Company assumes that a 4 tonne system will meet the heating and cooling requirement of the average 1,800 sq ft to 2,400 sq ft home in Ontario.

The number of tonnes depends on the size of home and the vintage (age, insulation condition etc.). At this time, the Company has not undertaken an analysis of the loop size requirement based on geography.

e) No. Enbridge did not consider calculating a service fee for each of the different types of housing stock or geographic area. The primary determinant for the fee is the size of the geothermal loop. On an exception basis, Enbridge may require a contribution in aid of construction in cases where the cost of installing the geothermal loop is particularly high.

f) No, Enbridge did not include GreenON funding in the DCF model. Enbridge expects the GreenOn funding to subsize the heat pump system not the geothermal loops. If GreenON funding is not received, the customer forecast may drop as geothermal systems will become relatively less economical.

g) CCA Class 43.2 has been used.

h) Please see the table below.

Table 5. Scenario Analysis for Geothermal Energy Services

Scenario	Service Fee	Accumulated NPV at Year 40	PI at Year 40
Base Case	$25.07 per tonne per month	$ 16,679,865	1.100
Scenario 1(a) Base case cost of debt + 50 bps	$25.07 per tonne per month	$ 12,620,742	1.077
Scenario 1(b) Base case cost of debt + 100 bps	$25.07 per tonne per month	$ 8,814,990	1.054
Scenario 1(c) Base csae ROE + 100 bps	$25.07 per tonne per month	$ 10,421,964	1.064
Scenario 1(d) Base case ROE + 300 bps	$25.07 per tonne per month	$ (342,288)	0.998
Scenario 1(e) 50/50 D/E ratio	$25.07 per tonne per month	$ 3,735,821	1.024
Scenario 1(f) 35/65 D/E ratio	$25.07 per tonne per month	$ (7,132,935)	0.953
Scenario 2 Base case capital investment ($237,148,543)+10% increase	$25.07 per tonne per month	$ 4,156,014	1.023
Scenario 3 Base case O&M expense +10% increase (Year 1 to Year 40)	$25.07 per tonne per month	$ 14,309,868	1.086

ANWAATIN INTERROGATORY #6

INTERROGATORY

Issue 2

Reference: • Exhibit B / Tab 1 / Schedule 1 / pp. 27-28, #79-81 and #83
• Issues 2.4, 4.1 and 4.2

Preamble: Enbridge states that it has built a discounted cash flow (**DCF**) model using a 10-year customer forecast and it expects about 170 customers in year 1 and, over a 10-year period, about 18,000 customers. This is based on expected demand, current capacity in the market, and ramp up capability of the market to meet demand. Enbridge also states that costs may depend on geographical and geological construction uncertainties.

a) Please explain Enbridge's approach to First Nation reserve markets for the GES Program.

b) Please provide estimates and assumptions for the number of First Nation customers to be served in years 1 through 10.

c) Please provide details on geological uncertainties for each geographical area with respect to specific geological uncertainties for First Nation reserve communities.

d) Please breakdown the forecast of 18,000 customers in year 10 by First Nation reserve community in Ontario, and discuss the geological construction uncertainties for each of the areas.

e) Please explain what is the expected demand across Ontario First Nation reserve communities over the ten-year period? Please provide all supporting documentation including data, assumptions and analysis.

RESPONSE

a) Enbridge acknowledges that many First Nations communities may benefit from participation in the Company's proposed Geothermal Energy Services ("GES") program. As of yet the Company has not undertaken an assessment of the market potential for the GES program in these communities. Enbridge's GES proposal has been designed generically to be suitable all potential customers of the proposed

service. Once the Board has rendered a decision in this proceeding Enbridge will assess the degree of interest the various First Nations communities may have in partaking in the GES program and how best to work with these communities to deliver the GES program to them.

b) The Company has not developed estimates of the number of First Nation GES customers that could be served in years one through ten of the program.

c) The determination and documentation of the geological details of First Nation communities that would be candidates for the Company's GES would be a costly and time consuming exercise and has not been undertaken by the Company at this time. Such assessments will be undertaken on a case-by-case basis once the Company has determined which First Nations communities are interested in its GES service and the market potential of these communities.

d) Please see responses to b) and c) above.

e) Please see the response to b) above.

APPrO INTERROGATORY #4

INTERROGATORY

Issue 2

Reference: i) Exhibit B Tab 1 Schedule 1

Preamble: APPrO would like to understand the economics of customers utilizing a geothermal service.

Questions:

(a) Please explain fully why Enbridge proposes a service fee based on a "per tonne" metric compared to a rate based on the cost of owning and operating the assets.

(b) Is heating or cooling the determining factor in sizing the geothermal loops?

(c) Please explain how the average 4 tonnes per customer was derived.

(d) How will a customer's natural gas consumption change with the use of a geothermal system and how will this impact other customers' rates. \

(e) Please describe the nature of the target residential geothermal customer.

(f) Please provide a detailed long term economic analysis illustrating (including assumptions) of a typical target customer's economic incentive to convert to a geothermal system.

(g) Please provide a detailed side by side long-term economic comparison for a typical target customer illustrating two options:
   i. A geothermal system as proposed by Enbridge,
   ii. A customer developing and operating its own geothermal system that is installed by a qualified contractor.

(h) At paragraph 23, Enbridge notes that "*Homeowners will be eligible for rebates of up to $20,000 for ENERGY STAR certified ground source heat pumps*" from GreenON. Since the underground geothermal loops are an expensive component, if not the most expensive component of the overall geothermal system, please explain:

i. If these any of these GreenON funds or other funding opportunities are, or could be eligible to offset the geothermal loop costs either directly or as some form of contribution in aid of construction paid by the homeowner?

ii. Did Enbridge explicitly seek out GreenON funding or other funding opportunities to offset the construction costs of the geothermal loops? If not, please explain why.

iii. Please provide the typical cost of installing a residential geothermal loop detailed by cost category.

iv. Please provide the typical cost of purchasing and installing the balance of the geothermal system that would be the customer's responsibility.

RESPONSE

(a) The Company is proposing a service fee based on "per Tonne" of heating capacity. The majority of costs of owning an operating a geothermal loop relate to the capital investment which is closely related to the heating capacity tonnage or length and depth of pipe in the ground. Therefore the Company believes it is appropriate to structure the service fee in terms of tonnes of heating capacity.

(b) Geothermal systems are required to be sized to cover 70% to 80% of the peak heating requirement of a home which usually covers 100% of the cooling capacity required for Ontario's climate.

(c) Based on current building designs and heating requirements of new homes, it is estimated that the average home size lies between 1800-2400Sq. Ft. with average peak heating requirements of <50,000 btu/h. Using this data, the Company assumed that a 4 tonne system will meet the heating and cooling requirement of the average 1,800 sq ft to 2,400 sq ft home in Ontario.

(d) It is expected that the geothermal customer will use little to no natural gas in their homes. Over a 10 year period, using Enbridge's customer additions forecast of approximately 18,000 geothermal customers, the impact on Enbridge's 2.2 million current customers will be negligible.

(e) Please see the response to Board Staff Interrogatory #12 (a), filed at Exhibit I.2.EGDI.STAFF.12.

(f) Please see response to Board Staff Interrogatory #10 (c), filed at Exhibit I.2.EGDI.STAFF.10.

(g) i) and ii) Please see the table below.

Comparison between Enbridge GES and Customer Procured Geothermal System										
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Energy Costs										
From Board Staff 10 c)	837.6	881.1	901.9	927.7	992.0	1055.5	1130.7	1174.1	1204.9	1235.5
Enbridge GES Program										
Geothermal Service fees	1,203.4	1,203.4	1,203.4	1,203.4	1,203.4	1,203.4	1,203.4	1,203.4	1,203.4	1,203.4
Heat Pump Cost	16,000.0									
Provincial rebate	(12,000.0)									
Total Cash flow out $	**6,040.9**	**2,084.5**	**2,105.2**	**2,131.1**	**2,195.4**	**2,258.8**	**2,334.1**	**2,377.4**	**2,408.2**	**2,438.9**
NPV	**$20,284.39**									
Customer procured geothermal system										
Geothermal loop costs	12,000.0									
Heat Pump Cost	16,000.0									
Provincial rebate	(12,000.0)									
Total energy related costs $	**16,837.6**	**881.1**	**901.9**	**927.7**	**992.0**	**1,055.5**	**1,130.7**	**1,174.1**	**1,204.9**	**1,235.5**
NPV	**$22,669.22**									
Assumptions										
Energy costs from Board Staff 10 c)										
4 Tonne home										
10 year analysis										

The two options are fundamentally different and a side by side comparison can be misleading. In the Enbridge GES model, the underground loop infrastructure is installed, owned maintained and at the end of its life replaced by Enbridge similar to natural gas lines to homes. In the case of the customer procured option, the customer will pay for the installation and may have to pay for maintenance, repair or replacement. Enbridge's proposed GES program is meant to address the barriers set out in the response to Board Staff Interrogatory #2 (a) filed at Exhibit I.1.EGDI.STAFF.2. Please also see the response to Board Staff Interrogatory #10 (c) filed at Exhibit I.2.EGDI.STAFF.10 for an analysis of the cost-effectiveness of installing a geothermal system in a gas heated home.

(h)

i. The GreenON funds are for the full geothermal system, inclusive of an ENERGY STAR certified ground source heat pump. The customer receives the rebate amounts, and allocates as they wish. Under the Enbridge Geothermal Energy Services program, it is assumed that the full rebate will be allocated to the heat pump system because there is no up-front customer cost for the geothermal loop.

ii. The GreenON funding is directed at the customers not Enbridge and in the model the Company is proposing, it will be directed to the heat pump system that the customer will be responsible for.

iii. Please see response to Board Staff Interrogatory #12 (d) (i) filed at Exhibit I.2.EGDI.STAFF.12.

iv. There are a variety of available models in the market for the heat pump system. A typical 4 tonne system can cost between $10,000 to $20,000.

APPrO INTERROGATORY #5

INTERROGATORY

Issue 2

Reference i) Exhibit B Tab 1 Schedule 1, paragraphs 19-20

> *Enbridge sees its role as that of a facilitator that can assist RNG producers in the process of upgrading raw untreated biogas into pipeline quality RNG and the injection and transportation of this gas to market.*
>
> *The Company proposes to offer RNG upgrading services on an optional basis. As such RNG producers will have the choice of upgrading biogas to pipeline quality themselves or having Enbridge perform this function for them.*

Preamble: Enbridge indicates that it is a facilitator of the RNG service but at the same time confirms that customers have the option of arranging alternate methods of providing the service. APPrO would like to understand the implications of offering such a service.

Questions:

(a) Please compare the service terms, including but not limited to the cost/rate, for a customer acquiring this service from Enbridge versus alternate private service providers.
(b) Please comment on whether it is typical for private service providers to offer a rate structure similar to the rate structure proposed by Enbridge, whereby other customers help to cross subsidize the service in certain years
(c) Please explain if the rate for this service would be fixed over the term of the contract or if it would vary based on the same Board approved rate adjustment mechanism for other Enbridge services.
(d) Please explain how Enbridge would account for further capital investment that may be required from time to time to continue to provide service over the life of the contract.
(e) Please explain all risks in detail, that ratepayers would be exposed to in each of the proposed RNG/GES programs (for example: in the event that the Board authorizes different rates of return on rate base in the future than what has been used in the initial fee setting will Enbridge seek a higher return on the RNG/GES rate base and if so who will pay for it?) In the event that other financial risks materialize over the life of the program that are not identified by Enbridge, will

Enbridge or the customer receiving the service bear the impact of any of these risks? Please explain.

(f) Does Enbridge currently have any letters of intent, or conditional contracts with potential customers of any of the services that are proposed? If so please describe the nature of the commitment, number, volumes etc.

RESPONSE

(a) Enbridge is not aware of any other current service providers for this service. The Company is not in a position to undertake the requested comparison of its RNG upgrading service terms to those of other potential RNG upgrading service providers since the Company is not privy to the service terms of unknown other potential service providers.

(b) See response to part (a).

(c) Please see the Company's response to Board Staff Interrogatory #9, part c) filed at Exhibit I.2.EGDI.STAFF.9.

(d) The Company will establish suitable warranties and protections from manufacturers and installation contractors to cover future unanticipated future capital costs for RNG processing and injection facilities. Any changes required by the customer will result in adjustments to the customer's fees to cover the associated additional costs.

(e) Please see the Company's responses to APPrO Interrogatory #2, part c) filed at Exhibit I.1.EGDI.APPrO.2 and FRPO Interrogatory #4 filed at Exhibit I.2.EGDI.FRPO.4 (note that these responses include cross-references to additional responses).

(f) With respect to RNG Enabling services, Enbridge currently has one biogas upgrading and injection services agreement in place and is in discussion with other potential RNG producers. The agreement that has been executed covers both RNG upgrading and injection of RNG volumes into the Enbridge gas distribution system. Under this agreement, Enbridge is responsible for the construction, operation and maintenance of the RNG upgrading and injection facility.

APPrO INTERROGATORY #6

INTERROGATORY

Issue 2

Reference: i) Exhibit B Tab 1 Schedule 1, Appendix 5, and 7

Preamble: APPrO would like to understand the assumptions included in these appendices for the RNG Enabling Services Program.

Questions:

(a) Please recalculate the table in each appendix noted in Reference i), and expand Line 11 to include:
   i. Number of customers
   ii. Revenue by customer
   iii. Annual volumes by customer (m3)

(b) The capital in line 1 of each appendix is a single entry and revenue in line 11 is also held constant. Is Enbridge forecasting any incremental customers after year 1. If so, how will these analyses be affected if customer growth occurs over the 20 year Program horizon?

(c) Will the RNG rate be set up as a separate rate class, with all RNG producers paying the same rate, or will rates be individually calculated?

(d) If additional customers are added over time, will Enbridge create segregated rate bases for each vintage of customer with segregated vintage rates or will Enbridge pool the assets and adjust the rates for all customers as new customers are added? Please explain fully.

(e) Please explain what happens after the 20 year forecast horizon for any undepreciated rate base?

(f) In the event that Enbridge is still providing service after year 20, how will rates be determined?

RESPONSE

(a) The tables included are project specific; therefore, there is only one customer in the example. The customer will pay a fixed fee per month, based on the costs to serve that customer.

(b) See response to part (a). Additional customers will not impact the fees for other customers.

(c) The fees for each customer and project will be individually calculated based on the costs of the project.

(d) No. Enbridge will track the sufficiency and deficiency associated with each project on an individual basis.

(e) The depreciation timeframe for the assets is intended to match the duration of the RNG Enabling service contract. As such, there should not be any undepreciated assets at the end of the contract term.

(f) The rates for service continuing past the term of the RNG Enabling service contract will be determined on an updated cost of service calculation at that time.

APPrO INTERROGATORY #7

INTERROGATORY

Issue 2

Reference: i) Exhibit B Tab 1 Schedule 1, paragraph 60

Preamble: APPrO would like to understand the options available for RNG producers.

Questions:

(a) In the event that a RNG customer requests that Enbridge transport RNG to other locations within its immediate contiguous distribution system or to other locations that are connected but non-contiguous (e.g. Dawn) will the RNG producer be subject to a transportation fee similar for example, to the fee that Union charges local natural gas producers to transport gas to a liquid point? Please explain fully.

(b) In the event that the RNG requires a system reinforcement or modification (e.g. the local markets are too small to absorb the RNG production at certain times of the year and a regulator station in the system prevents physical backflow during low flow periods), will Enbridge have the right to refuse to deliver such supplies and/or charge the RNG producer the full incremental cost of the reinforcement or modification?

RESPONSE

(a) Once injected, RNG will be treated the same as conventional natural gas. Where possible, Enbridge will utilize existing direct purchase tools to transport gas to Dawn. For example a producer could utilize an Enhanced title transfer for a one time movement of RNG from the CDA to Dawn. Producers can also utilize exchange agreements to move the RNG to Dawn.

(b) Enbridge can only accept gas when system capacity is available. If applicable, the producers would be provided options for connection to the Enbridge system. In some cases connection to a different system or pipeline can increase the takeaway capacity. The costs of the connection to the Enbridge system will be included into the RNG injection services fee.

CBA INTERROGATORY #4

INTERROGATORY

2. Cost Consequences:

2.1. Is the methodology to set services fees for the RNG Enabling Program – Upgrading Service reasonable and appropriate?

REF: Exhibit B/Tab 1 Schedule 1 page 7

PREAMBLE:

The Company proposes to offer RNG upgrading services on an optional basis. As such RNG producers will have the choice of upgrading biogas to pipeline quality themselves or having Enbridge perform this function for them. All RNG producers who wish to use Enbridge's distribution system to transport RNG will have to contract with Enbridge for RNG injection services. This will enable the Company to meet its responsibilities as a distributor of natural gas and ensure the safe and reliable distribution of RNG to market.

What, if any, benefits, monetary or otherwise, are there for RNG producers that use both the upgrading and injection services to be provided by EGD as opposed to only using one or the other of those services?

RESPONSE

All RNG producers must use the RNG injection service. There may be savings and convenience benefits to RNG producers who also acquire RNG upgrading services from Enbridge.

CBA INTERROGATORY #5

INTERROGATORY

2. Cost Consequences:

2.1. Is the methodology to set services fees for the RNG Enabling Program – Upgrading Service reasonable and appropriate?

REF: Exhibit B/Tab 1 Schedule 1 page 19

PREAMBLE:

Tables 2 and 3 set out a hypothetical example for a single RNG production facility to illustrate how the service charges for the Company's Biogas Upgrading and RNG Injection Services are to be determined.

With respect to the upgrading and injection services, are the required capital investments all specific to each RNG producer contracting for the service, or are there material capital investments that won't be specific to particular RNG producers? If there are non-RNG producer specific capital investments required please describe the nature of those investments, the materiality of those costs, benefits to rate payers and describe how EGD could recover those investments.

RESPONSE

Yes, the required capital investments are specific to each RNG producer contracting for the service.

CBA INTERROGATORY #6

INTERROGATORY

2. Cost Consequences:

2.1. Is the methodology to set services fees for the RNG Enabling Program – Upgrading Service reasonable and appropriate?

REF: Exhibit B/Tab 1 Schedule 1 page 19.

PREAMBLE:

The determination of the service fees for Upgrading and Injection Services will be site specific and based on the fully allocated costs associated with the services in each particular instance.

Please describe the nature and forecast the level of fully allocated costs EGD expects to recover from a typical RNG producer from both upgrading and injection services. Please explain how and when that cost recovery will be managed.

RESPONSE

The nature of the O&M costs that will be allocated to RNG Enabling Service customers is described in response to Board Staff Interrogatory #11, filed at Exhibit I.2.EGDI.STAFF.11. The level of these costs will vary from year to year, based on current estimates. The current example of relevant costs for RNG Enabling Service customers who contract in 2018 is seen in the calculation of example Rate 400 and Rate 401 fees set out in the pre-filed evidence.

CBA INTERROGATORY #7

INTERROGATORY

2. Cost Consequences:

2.2. Is the methodology to set services fees for the RNG Enabling Program – Injection Service reasonable and appropriate?

REF: Exhibit B/Tab 1 Schedule 1 page 4

PREAMBLE:

In June 2016 the Ontario Ministry of Environment and Climate Change (the "MOECC") published its Climate Change Action Plan (the "CCAP"). The CCAP consolidated the Province's plans to bring together effective initiatives designed to enable Ontario to achieve its GHG reduction targets. The plan outlines how the Province intends to direct the Cap and Trade proceeds towards projects that will create good jobs, help families and businesses become more energy-efficient, and accelerate Ontario's transition to a low-carbon economy.

Please discuss whether EGD's proposed RNG Enabling Program qualifies for investment from the provincial government as a measure intended to help introduce RNG in the province. If the proposed program qualifies for such funding, please discuss how such funding would be used to reduce the cost of the proposed services to RNG producers. If the proposed program does not qualify for such funding, please explain why not?

RESPONSE

It is the Company's understanding that the development of RNG production facilities may be supported by government subsidies funded through Cap and Trade monies collected by the province. The terms and conditions of any such funding arrangements will be negotiated between the biogas producer and the provincial government. It will be up to the biogas producer to determine how best to apply these funds given the terms and conditions of the funding agreement they enter into with the province. This might result in customized arrangements with upgrading customers, to allow for effective use of the Government funding.

CBA INTERROGATORY #8

INTERROGATORY

2. Cost Consequences:

2.2. Is the methodology to set services fees for the RNG Enabling Program – Injection Service reasonable and appropriate?

REF: Exhibit B/Tab 1 Schedule 1 page 9

PREAMBLE:

In applying the EBO 188 Guidelines, Enbridge has or will determine the capital, operating and financing cost requirements for these programs over the forecast horizon.

Please explain how the financing costs for the RNG Enabling Program will be determined.

RESPONSE

The EBO 188 Guidelines serve to standardize the elements to be used in the discounted cash flow ("DCF") analysis as well as establish the parameters for the costs and revenues that are the inputs to that analysis. One of the specific parameters set-out in the guideline is the discount rate to be used in these analyses which is defined as “a discount rate equal to the incremental after-tax cost of capital based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity” (Final Report of the Board in the Matter of a hearing to inquire into, hear and determine certain matters relating to natural gas system expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc., January 30, 1998, Appendix B, para. 300).

The discount rate of 5.43% used in the feasibility test set out in Exhibit B, Tab 1, Schedule 1, Appendices 5 and 7 is based on a debt / equity ratio of 64 / 36, a cost of debt of 4.66% and an Board approved rate of return on equity of 9.00%. The discount rate used for the purpose of determining fees payable under the Company’s Rate 400 and Rate 401 will be determined in the same manner in all cases, however, the discount rate applied may vary from year to year based on changes in the above noted parameters.

CBA INTERROGATORY #9

INTERROGATORY

2. Cost Consequences:

2.2. Is the methodology to set services fees for the RNG Enabling Program – Injection Service reasonable and appropriate?

REF: Exhibit B/Tab 1 Schedule 1 page 18

PREAMBLE:

The RNG producer will be charged separate service fees for each of the two services offered by the Company. Each service fee will be derived from a discounted cash flow ("DCF") analysis. The DCF analysis will be based on the principles and parameters set out in the OEB's EBO 188 feasibility guideline. The fee for each service (Upgrading or Injection) will be site specific and set so as to recover operating and maintenance costs, depreciation, utility's return on investment, and taxes while achieving a PI equal to or greater than 1.0 over the service life of the plant. Enbridge will charge a levelized (constant) service fee for each month of the term of the contract.

Please confirm that it is EGD's proposal to fix the monthly charge for RNG Enabling Program services at the outset of the relevant contract, and that the monthly charge is not proposed to change for the duration of the contract. If not confirmed, please explain how EGD intends to modify the monthly charge throughout the term of the contract.

RESPONSE

Enbridge confirms that it is its proposal to fix the monthly charge for RNG Enabling Program services at the outset of the relevant contract, and that the monthly charge is not proposed to change for the duration of the contract. Please also see response to Board Staff Interrogatory #9(c), filed at Exhibit I.2.EGDI.STAFF.9 and APPrO Interrogatory #5(d), filed at Exhibit I.2.EGDI.APPrO.5.

CBA INTERROGATORY #10

INTERROGATORY

2. Cost Consequences:

2.2. Is the methodology to set services fees for the RNG Enabling Program – Injection Service reasonable and appropriate?

REF: Exhibit B/Tab 1 Schedule 1 page 19

PREAMBLE:

The determination of the service fees for Upgrading and Injection Services will be site specific and based on the fully allocated costs associated with the services in each particular instance.

How does EGD's proposed costing methodology and forecast costs for Upgrading and Injection Services compare with other jurisdictions?

RESPONSE

Enbridge not in a position to compare what it will charge for RNG Upgrading and Injection Services to that of other jurisdictions at this time. The Company is in the early stages of designing its first upgrading and injection station. Enbridge is consulting with equipment providers and installation contractors and monitors industry practices in other jurisdictions. The costs of the upgrading and injection facilities and the resulting rates will be refined as the Company moves from the conceptual stage to detailed design and then to execution.

CBA INTERROGATORY #11

INTERROGATORY

2. Cost Consequences:

2.4.What are the appropriate terms and conditions of the Geothermal Energy Service Program, RNG Enabling Program – Upgrading Service, and RNG Enabling Program – Injection Service?

REF: Exhibit B/Tab 1 Schedule 1 page 7

PREAMBLE:

The Company proposes to offer RNG upgrading services on an optional basis. As such RNG producers will have the choice of upgrading biogas to pipeline quality themselves or having Enbridge perform this function for them. All RNG producers who wish to use Enbridge's distribution system to transport RNG will have to contract with Enbridge for RNG injection services. This will enable the Company to meet its responsibilities as a distributor of natural gas and ensure the safe and reliable distribution of RNG to market.

a) Please explain why RNG Producers must use EGD's injection service as opposed to using a 3rd party for all or a part of the injection service? In answering please discuss each step in the injection process and why only EGD can provide that aspect of injection, or whether that aspect of the service could be provided by a third party.

b) Does EGD directly inject all the gas that ends up in its system itself, or do third parties ever inject gas into the EGD system? If so please provide details.

RESPONSE

a) Please see the Company's response to Board Staff Interrogatory #1 c) filed at Exhibit I.1.EGDI.STAFF.1.

b) Enbridge directly injects all gas volumes into its gas distribution system through facilities owned, controlled and operated by the Company.

CBA INTERROGATORY #12

INTERROGATORY

2. Cost Consequences:

2.4.What are the appropriate terms and conditions of the Geothermal Energy Service Program, RNG Enabling Program – Upgrading Service, and RNG Enabling Program – Injection Service?

REF: Exhibit B/Tab 1 Schedule 1 page 21

PREAMBLE:

In the event that Enbridge is purchasing RNG as part of the Company's gas supply mix, the RNG producer will be able to respond to tenders for the sale of RNG to the Company.

Please describe EGD's plans to procure RNG injected into its distribution system as a result of the RNG Enabling Program. Please discuss any barriers preventing EGD from extending the scope of the RNG Enabling Program to include the procurement of RNG injected into EGD's system as a result of the program such that its customers will directly benefit from the program through the use of RNG as part of their gas supply.

Does EGD plan to distinguish between RNG that has been upgraded by EGD and RNG that has been upgraded by a 3rd party when deciding to procure RNG? What, if any, advantages will RNG producers that use EGD's Upgrade and Injection Services have over other RNG producers when competing for procurement contracts with EGD?

RESPONSE

Enbridge's RNG procurement proposal has been described in detail as part of the Company's 2018 Cap and Trade Compliance Plan filed with the Ontario Energy Board under docket number EB-2017-0224.[1] The RNG Enabling Program has been developed to enable the injection of RNG into the Enbridge's distribution system and is not dependent on the procurement of the RNG by the Company.

RNG procurement is a gas supply function. The Company's procurement of RNG will be subject to a rigorous tendering process. Enbridge has taken steps to separate its

[1] Exhibit C, Tab 5, Schedule 2

RNG procurement program from its RNG Enabling Program so as preserve the integrity of this tendering process.

Enbridge will not distinguish between RNG that has been upgraded by the Company and RNG that has been upgraded by a 3rd party when deciding to procure RNG. The Injection Service will be a mandatory service for all parties interested in injecting RNG onto the Company's distribution system.

CBA INTERROGATORY #13

INTERROGATORY

2. Cost Consequences:

2.4.What are the appropriate terms and conditions of the Geothermal Energy Service Program, RNG Enabling Program – Upgrading Service, and RNG Enabling Program – Injection Service?

REF: Exhibit B/Tab 1 Schedule 1 pages 17 to 18

PREAMBLE:

Enbridge will provide these services subject to the Company entering into contracts with the RNG producers for the provision of these service(s). Items to be addressed in the contracts will include but not be limited to: the design, location, construction, operation, timing and costs of the required upgrading and injection facilities and related services. While the specific contents of each contract will be different (to reflect the details of the relevant facilities), the form of the contracts will be common or similar for all producers receiving Upgrading and / or Injection Service.

a) How flexible is EGD willing/prepared to be in terms of volumes delivered year over year? How will variations in volumes delivered affect the monthly cost paid by a Producer, if at all?

b) Please discuss whether there will be a cap on production under contracts for either upgrading or injection services and if so how that cap will operate.

c) How does EGD propose to allocate the risks associated with any operational inability on the part of EGD to perform upgrading or injection services under a contract, i.e. in the event of a failure of any of EGD's equipment?

d) How does EGD propose to allocate the risk related to the loss of RNG volumes as a result of inefficient or underperforming upgrading or injection services?

e) Does EGD propose to offer contract terms that are equal to or better than what is available in the market outside Ontario? Please explain what terms are being considered.

RESPONSE

a) Enbridge is prepared to work with RNG production proponents in terms of volumes of RNG to be delivered on a daily, monthly and annual basis taking into consideration the nature of the facilities built for the producer and the constraints identified in the Company's response to Board Staff Interrogatory #1, part c) filed at Exhibit I.1.EGDI.STAFF.1. Acceptable variations in RNG volumes injected into the Company's gas distribution system will not affect the monthly cost paid by an RNG producer.

b) Please see the Company's response to part a) to this interrogatory. The Company will endeavour to accept as much RNG as possible subject to applicable constraints. Any cap on RNG delivery volumes will be site specific.

c) With respect to RNG upgrading Enbridge will agree to site specific service levels. With respect to RNG injection services, to protect against system constraints that may arise from time to time, the Company will not warrant the acceptance of RNG volumes at all times.

d) Please see response to part c).

e) With respect to the Enbridge RNG Enabling proposals the Company is of the view that its service offering is comparable to that offered by FortisBC Energy Inc. in British Columbia. A pro forma copy of the Company's Rate 400 service agreement and Rate 401 service agreement has been filed in the response to Board Staff Interrogatory #6 filed at Exhibit I.2.EGDI.STAFF.6.

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

Issue 2 – Cost Consequences

Ref: Exhibit B / Tab 1 / Schedule 1 / Appendix 5 and 6

Preamble: Enbridge asserts that the Discounted Cash Flow (DCF) analysis approved by the Board for Natural Gas Distribution System Expansion Projects under the E.B.O. 188 guidelines should be applied to the RNG BMS, Injection and GESP Projects. Energy Probe wishes to compare and understand this analogy in more detail.

a) Please provide a comparison of the analysis in Appendix 5 to that for a typical (hypothetical) Natural Gas Community Expansion (CE) project under E.B.O. 188 Guidelines with the same capital cost.

b) Specifically, please tabulate and compare the input assumptions for each of the BMS and CE Projects

c) Please provide a revised analysis for the RNG BMS in Appendix 5, using the same assumptions a CE Project.

d) Please provide a revised revenue requirement schedule similar to Appendix 6.

RESPONSE

a) and b) The table below shows a comparison between the RNG upgrading service input assumptions and a CE project input assumptions. The table shows that the resulting PI from using the CE inputs is 1.21 versus 1.10. The key driver of the difference is that the RNG upgrading example includes an inflation factor for O&M whereas the CE example does not.

Input Assumptions	Community Expansion Project	RNG BMS	RNG BMS [using CE inputs]
Economic Feasibility Horizon	Residential - 40 Years Large Volume - 20 Years	20 Years	20 Years
Customer Addition Forecast	10 Years	N/A - one customer only	N/A - one customer only
Customer Revenue Horizon	Various - ends at 40 years for residential and 20 for large volume customers	20 Years	20 Years
Cost Basis	Incremental	Fully Allocated [Third parties]	Fully Allocated [Third parties]
Feasibility Parameters:			
Revenue Rate	QRAM	Fixed Monthly Rate	Fixed Monthly rate
Discount Rate (after-tax weighted average cost of capital)	5.41% (2017 OEB approved capital parameters)	5.43% (current OEB approved capital parameters)	5.43% (current OEB approved capital parameters)
CCA Rate	6%	Multiple	Multiple
Income Tax Rate	26.50%	26.50%	26.50%
Municipal Tax Rate	10 Yr. municipal exemption (field estimate thereafter)	0.59%	0.59%
Inflation assumption:			
Revenue	0%	0%	0%
O&M	0%	2%	0%
PI	1.00	1.10	1.21

c) See Attachment 1 to this response.

d) See Attachment 2 to this response.

ATTACHMENT 1

RNG BMS

ECONOMIC FEASIBILITY

RNG BMS
Economic Feasibility
Parameters and Results

Line No.	Col. 1 Description	Col. 2
FEASIBILITY PARAMETERS		
1.	Discount Rate	5.43%
2.	CCA Rate - Biogas Upgrading Plant	
3.	Energy components	50.00%
4.	Non- Energy components	20.00%
5.	Buildings components	4.00%
6.	Income Tax Rate	26.50%
7.	Municipal Tax Rate	0.59%
8.	Customer Revenue Horizon (Years)	20
9.	Capital Investment (Dollars)	
10.	Biogas Conditioning and Upgrading Plant Capital	7,419,759
11.	Working Capital (Days of Revenue)	30
FEASIBILITY RESULTS		
12.	Net Present Value (Dollars)	1,512,653
13.	Profitability Index	1.21

RNG BMS
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 2 Year 0	Col. 3 Year 1	Col. 4 Year 2	Col. 5 Year 3	Col. 6 Year 4	Col. 7 Year 5	Col. 8 Year 6	Col. 9 Year 7	Col. 10 Year 8	Col. 11 Year 9	Col. 12 Year 10
	Discount factors to project outset	0.9739	0.9237	0.8762	0.8310	0.7882	0.7476	0.7091	0.6726	0.6379	0.6051	0.5739
	INCREMENTAL CAPITAL INVESTMENT											
1.	Biogas Conditioning and Upgrading Plant	(7,419,759)										-
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	(7,419,759)	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	(110,750)	-	-	-	-	-	-	-	-	-
5.	Total Investment	(7,419,759)	(110,750)	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	(7,226,130)	(102,304)	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(7,226,130)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)
	CCA TAX SHIELD											
8.	CCA Tax Shield	-	414,990	632,014	333,302	180,763	101,938	60,469	38,080	25,552	18,211	13,671
9.	PV Of CCA Tax Shield At Project Outset	-	383,341	553,741	276,981	142,480	76,210	42,879	25,612	16,300	11,019	7,846
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	-	383,341	937,083	1,214,063	1,356,544	1,432,754	1,475,632	1,501,244	1,517,544	1,528,564	1,536,409
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)											
11.	Biogas Conditioning and Upgrading Service Revenues	-	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000
12.	O&M Expenses	-	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)
13.	Net Operating Cash (Before Taxes)	-	889,000	889,000	889,000	889,000	889,000	889,000	889,000	889,000	889,000	889,000
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	-	821,202	778,900	738,778	700,722	664,627	630,391	597,918	567,119	537,906	510,197
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	-	821,202	1,600,102	2,338,880	3,039,602	3,704,229	4,334,620	4,932,538	5,499,657	6,037,563	6,547,760
	TAXES											
16.	Income Tax (Before Interest Tax Shield)	-	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)
17.	Municipal Tax	-	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)
18.	Total Taxes	-	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)
19.	PV of Total Taxes At Project Outset	-	(247,340)	(234,599)	(222,515)	(211,053)	(200,181)	(189,869)	(180,089)	(170,812)	(162,014)	(153,668)
20.	**ACCUMULATED PV OF TOTAL TAXES**	-	(247,340)	(481,940)	(704,455)	(915,508)	(1,115,689)	(1,305,558)	(1,485,647)	(1,656,459)	(1,818,473)	(1,972,141)
	ACCUMULATED NPV AND PI											
21.	Net Present Value	(7,226,130)	(6,371,232)	(5,273,189)	(4,479,946)	(3,847,796)	(3,307,140)	(2,823,740)	(2,380,299)	(1,967,692)	(1,580,781)	(1,216,406)
22.	Profitability Index	0.000	0.131	0.280	0.389	0.475	0.549	0.615	0.675	0.731	0.784	0.834

RNG BMS
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 13 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
	Discount factors to project outset	0.5443	0.5163	0.4897	0.4645	0.4406	0.4179	0.3963	0.3759	0.3566	0.3382
	INCREMENTAL CAPITAL INVESTMENT										
1.	Biogas Conditioning and Upgrading Plant	-	-	-	-	-	-	-	-	-	
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	-	-	-	-	-	-	-	-	-
5.	Total Investment	-	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	(7,328,434)	**(7,328,434)**
	CCA TAX SHIELD										
8.	CCA Tax Shield	10,696	8,636	7,141	6,013	5,137	4,443	3,884	3,429	3,054	24,068
9.	PV Of CCA Tax Shield At Project Outset	5,822	4,459	3,497	2,793	2,263	1,857	1,539	1,289	1,089	8,140
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	1,542,231	1,546,690	1,550,187	1,552,980	1,555,243	1,557,100	1,558,639	1,559,928	1,561,017	**1,569,156**
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)										
11.	Biogas Conditioning and Upgrading Service Revenues	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000
12.	O&M Expenses	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)
13.	Net Operating Cash (Before Taxes)	889,000	889,000	889,000	889,000	889,000	889,000	889,000	889,000	889,000	889,000
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	483,916	458,989	435,346	412,920	391,650	371,476	352,340	334,191	316,976	300,648
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	7,031,676	7,490,665	7,926,010	8,338,931	8,730,581	9,102,056	9,454,397	9,788,587	10,105,563	**10,406,211**
	TAXES										
16.	Income Tax (Before Interest Tax Shield)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)	(223,984)
17.	Municipal Tax	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)	(43,777)
18.	Total Taxes	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)	(267,761)
19.	PV of Total Taxes At Project Outset	(145,752)	(138,244)	(131,123)	(124,369)	(117,962)	(111,886)	(106,123)	(100,656)	(95,471)	(90,553)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(2,117,893)	(2,256,138)	(2,387,261)	(2,511,629)	(2,629,592)	(2,741,478)	(2,847,600)	(2,948,256)	(3,043,727)	**(3,134,280)**
	ACCUMULATED NPV AND PI										
21.	Net Present Value	(872,420)	(547,217)	(239,497)	51,847	327,798	589,244	837,001	1,071,825	1,294,418	1,512,653
22.	Profitability Index	0.881	0.925	0.967	1.007	1.045	1.080	1.114	1.146	1.177	**1.206**

RNG BMS
Revenue and Revenue Requirement

Line No.		Col. 1 Description	Col. 2 Year 0	Col. 3 Year 1	Col. 4 Year 2	Col. 5 Year 3	Col. 6 Year 4	Col. 7 Year 5	Col. 8 Year 6	Col. 9 Year 7	Col. 10 Year 8	Col. 11 Year 9	Col. 12 Year 10
1		Capital	7,419,759										
2		**Rate Base**											
3		Balance, beginning		7,419,759	7,159,521	6,788,533	6,417,545	6,046,557	5,675,569	5,304,581	4,933,593	4,562,605	4,191,617
4	+	Additions											
5	+	Working Capital Additions		110,750	0	0	0	0	0	0	0	0	0
6	-	Depreciation		(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)
7		Balance, ending	7,419,759	7,159,521	6,788,533	6,417,545	6,046,557	5,675,569	5,304,581	4,933,593	4,562,605	4,191,617	3,820,629
8		Average Rate Base		7,289,640	6,974,027	6,603,039	6,232,051	5,861,063	5,490,075	5,119,087	4,748,099	4,377,111	4,006,123
9		**Revenue Requirement**											
10		Return on Rate Base		452,333	432,748	409,728	386,708	363,687	340,667	317,647	294,626	271,606	248,586
11		O&M		440,000	440,000	440,000	440,000	440,000	440,000	440,000	440,000	440,000	440,000
12		Municipal Taxes		43,777	43,777	43,777	43,777	43,777	43,777	43,777	43,777	43,777	43,777
13		Deprecation		370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988
14		Taxes		(344,556)	(643,564)	(241,544)	(38,401)	64,453	116,481	142,550	155,204	160,799	162,584
15		Revenue Requirement		962,541	643,949	1,022,949	1,203,072	1,282,905	1,311,913	1,314,962	1,304,595	1,287,169	1,265,935
16		**Revenue**											
17		Biogas Conditioning and Upgrading Service Revenue		1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000
18		**Sufficiency / (Deficiency)**		**366,459**	**685,051**	**306,051**	**125,928**	**46,095**	**17,087**	**14,038**	**24,405**	**41,831**	**63,065**

RNG BMS
Revenue and Revenue Requirement

Line No.		Col. 1 Description	Col. 13 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
1		Capital										
2		**Rate Base**										
3		Balance, beginning	3,820,629	3,449,641	3,078,654	2,707,666	2,336,678	1,965,690	1,594,702	1,223,714	852,726	481,738
4	+	Additions										
5	+	Working Capital Additions	0	0	0	0	0	0	0	0	0	0
6	-	Depreciation	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)	(370,988)
7		Balance, ending	3,449,641	3,078,654	2,707,666	2,336,678	1,965,690	1,594,702	1,223,714	852,726	481,738	110,750
8		Average Rate Base	3,635,135	3,264,147	2,893,160	2,522,172	2,151,184	1,780,196	1,409,208	1,038,220	667,232	296,244
9		**Revenue Requirement**										
10		Return on Rate Base	225,565	202,545	179,525	156,504	133,484	110,464	87,443	64,423	41,403	18,382
11		O&M	440,000	440,000	440,000	440,000	440,000	440,000	440,000	440,000	440,000	440,000
12		Municipal Taxes	43,777	43,777	43,777	43,777	43,777	43,777	43,777	43,777	43,777	43,777
13		Deprecation	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988	370,988
14		Taxes	162,240	160,650	158,293	155,436	152,235	148,788	145,156	141,384	137,502	133,533
15		Revenue Requirement	1,242,570	1,217,960	1,192,582	1,166,705	1,140,484	1,114,016	1,087,364	1,060,571	1,033,669	1,006,680
16		**Revenue**										
17		Biogas Conditioning and Upgrading Service F	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000	1,329,000
18		**Sufficiency / (Deficiency)**	**86,430**	**111,040**	**136,418**	**162,295**	**188,516**	**214,984**	**241,636**	**268,429**	**295,331**	**322,320**

ENERGY PROBE INTERROGATORY #7

INTERROGATORY

Issue 2 – Cost Consequences

Ref: Exhibit B / Tab 1 / Schedule 1 / Appendix 7

Preamble: Enbridge asserts that the DCF analysis approved by the Board for Natural Gas Distribution System Expansion Projects under the E.B.O. 188 Guidelines should be applied to the RNG BMS, Injection and GESP Projects. Energy Probe wishes to compare and understand this analogy in more detail.

a) Specifically tabulate and compare the input assumptions for each of the RNG Injection and CE Projects.

b) Please provide a revised analysis for the RNG Injection Project in Appendix 7, using the same assumptions as the hypothetical E.B.O. 188 CE project. Please provide a revised revenue requirement schedule.

RESPONSE

a) The table below shows a comparison between the RNG injection service input assumptions and a CE project input assumptions. The table shows that the resulting PI from using the CE inputs is 1.18 versus 1.10. There are 2 key drivers of the difference: 1) the use of fully allocated costs in the original example versus incremental costs in the CE example; and 2) RNG injection example includes an inflation factor for O&M whereas the CE example does not.

Input Assumptions	Community Expansion Project	RNG Injection	RNG Injection (Using CE inputs)
Economic Feasibility Horizon	Residential - 40 Years Large Volume - 20 Years	20 Years	20 Years
Customer Addition Forecast	10 Years	N/A - one customer only	N/A - one customer only
Customer Revenue Horizon	Various - ends at 40 years for residential and 20 for large volume customers	20 Years	20 Years
Cost Basis	Incremental	Fully Allocated	Incremental
Feasibility Parameters:			
Revenue Rate	QRAM	Fixed Monthly Rate	Fixed Monthly rate
Discount Rate (after-tax weighted average cost of capital)	5.41% (2017 OEB approved capital parameters)	5.43% (current OEB approved capital parameters)	5.43% (current OEB approved capital parameters)
CCA Rate	6%	6%	6%
Income Tax Rate	26.50%	26.50%	26.50%
Municipal Tax Rate	10 Yr. municipal exemption (field estimate thereafter)	0.59%	0.59%
Inflation assumption:			
Revenue	0%	0%	0%
O&M	0%	2%	0%
PI	1.00	1.10	1.18

b) Please see Attachments 1 and 2 to this response.

ATTACHMENT 1

RNG INJECTION

ECONOMIC FEASIBILITY

RNG INJECTION
Economic Feasibility
Parameters and Results

Line No.	Col. 1 Description	Col. 2
FEASIBILITY PARAMETERS		
1.	Discount Rate	5.43%
2.	CCA Rate - Biomethane Injection Capital	6.00%
3.	Income Tax Rate	26.50%
4.	Municipal Tax Rate	0.59%
5.	Customer Revenue Horizon (Years)	20
6.	Capital Investment (Dollars)	
7.	Biomethane Injection Capital	5,439,025
8.	Working Capital (Days of Revenue)	30
FEASIBILITY RESULTS		
9.	Net Present Value (Dollars)	961,720
10.	Profitability Index	1.18

RNG INJECTION
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 2 Year 0	Col. 3 Year 1	Col. 4 Year 2	Col. 5 Year 3	Col. 6 Year 4	Col. 7 Year 5	Col. 8 Year 6	Col. 9 Year 7	Col. 10 Year 8	Col. 11 Year 9	Col. 12 Year 10
	Discount factors to project outset	0.9912	0.9569	0.9076	0.8608	0.8165	0.7744	0.7345	0.6967	0.6608	0.6268	0.5945
	INCREMENTAL CAPITAL INVESTMENT											
1.	Bio-methane Injection capital	(5,439,025)										
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	(5,439,025)	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	(63,083)	-	-	-	-	-	-	-	-	-
5.	Total Investment	(5,439,025)	(63,083)	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	(5,391,295)	(60,364)	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(5,391,295)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)
	CCA TAX SHIELD											
8.	CCA Tax Shield	-	39,750	77,115	72,488	68,139	64,050	60,207	56,595	53,199	50,007	47,007
9.	PV Of CCA Tax Shield At Project Outset	-	38,036	69,989	62,401	55,635	49,603	44,225	39,430	35,155	31,344	27,945
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	-	38,036	108,025	170,426	226,062	275,665	319,890	359,320	394,476	425,819	453,765
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)											
11.	Bio-methane Injection Revenues	-	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
12.	O&M Expenses	-	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)
13.	Net Operating Cash (Before Taxes)	-	675,000	675,000	675,000	675,000	675,000	675,000	675,000	675,000	675,000	675,000
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	-	645,898	612,627	581,069	551,137	522,747	495,820	470,279	446,055	423,078	401,284
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	-	645,898	1,258,524	1,839,594	2,390,731	2,913,478	3,409,298	3,879,578	4,325,632	4,748,710	5,149,994
	TAXES											
16.	Income Tax (Before Interest Tax Shield)	-	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)
17.	Municipal Tax	-	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)
18.	Total Taxes	-	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)
19.	PV of Total Taxes At Project Outset	-	(193,732)	(183,753)	(174,287)	(165,310)	(156,794)	(148,718)	(141,057)	(133,791)	(126,899)	(120,362)
20.	**ACCUMULATED PV OF TOTAL TAXES**	-	(193,732)	(377,485)	(551,773)	(717,082)	(873,877)	(1,022,594)	(1,163,651)	(1,297,442)	(1,424,341)	(1,544,703)
	ACCUMULATED NPV AND PI											
21.	Net Present Value	(5,391,295)	(4,961,456)	(4,462,594)	(3,993,411)	(3,551,948)	(3,136,391)	(2,745,064)	(2,376,411)	(2,028,992)	(1,701,470)	(1,392,602)
22.	Profitability Index	0.000	0.090	0.181	0.267	0.348	0.425	0.496	0.564	0.628	0.688	0.745

RNG INJECTION
Economic Feasibility - 20 year Horizon
DCF Analysis

	Col. 1	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22
Line No.	Description	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
	Discount factors to project outset	0.5639	0.5348	0.5073	0.4811	0.4564	0.4329	0.4106	0.3894	0.3693	0.3503
	INCREMENTAL CAPITAL INVESTMENT										
1.	Bio-methane Injection capital										
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	-	-	-	-	-	-	-	-	-
5.	Total Investment	-	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	(5,451,658)	**(5,451,658)**
	CCA TAX SHIELD										
8.	CCA Tax Shield	44,186	41,535	39,043	36,701	34,499	32,429	30,483	28,654	26,935	233,522
9.	PV Of CCA Tax Shield At Project Outset	24,916	22,214	19,806	17,658	15,744	14,037	12,515	11,158	9,948	81,808
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	478,680	500,894	520,700	538,358	554,102	568,139	580,654	591,812	601,760	**683,568**
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)										
11.	Bio-methane Injection Revenues	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
12.	O&M Expenses	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)	(82,000)
13.	Net Operating Cash (Before Taxes)	675,000	675,000	675,000	675,000	675,000	675,000	675,000	675,000	675,000	675,000
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	380,613	361,007	342,411	324,773	308,044	292,176	277,125	262,850	249,310	236,468
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	5,530,608	5,891,615	6,234,026	6,558,800	6,866,843	7,159,019	7,436,144	7,698,995	7,948,305	**8,184,773**
	TAXES										
16.	Income Tax (Before Interest Tax Shield)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)	(170,371)
17.	Municipal Tax	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)	(32,090)
18.	Total Taxes	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)	(202,461)
19.	PV of Total Taxes At Project Outset	(114,162)	(108,282)	(102,704)	(97,413)	(92,395)	(87,636)	(83,122)	(78,840)	(74,779)	(70,927)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(1,658,865)	(1,767,147)	(1,869,851)	(1,967,264)	(2,059,660)	(2,147,296)	(2,230,417)	(2,309,257)	(2,384,036)	**(2,454,963)**
	ACCUMULATED NPV AND PI										
21.	Net Present Value	(1,101,236)	(826,296)	(566,782)	(321,764)	(90,372)	128,204	334,723	529,891	714,371	961,720
22.	Profitability Index	0.798	0.848	0.896	0.941	0.983	1.024	1.061	1.097	1.131	**1.176**

RNG INJECTION
Revenue and Revenue Requirement

Line No.		Col. 1 Description	Col. 2 Year 0	Col. 3 Year 1	Col. 4 Year 2	Col. 5 Year 3	Col. 6 Year 4	Col. 7 Year 5	Col. 8 Year 6	Col. 9 Year 7	Col. 10 Year 8	Col. 11 Year 9	Col. 12 Year 10
1		Capital	5,439,025										
2		**Rate Base**											
3		Balance, beginning		5,439,025	5,250,157	4,998,206	4,746,255	4,494,303	4,242,352	3,990,401	3,738,450	3,486,498	3,234,547
4	+	Additions											
5	+	Working Capital Additions		63,083	0	0	0	0	0	0	0	0	0
6	-	Depreciation		(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)
7		Balance, ending	5,439,025	5,250,157	4,998,206	4,746,255	4,494,303	4,242,352	3,990,401	3,738,450	3,486,498	3,234,547	2,982,596
8		Average Rate Base		5,344,591	5,124,181	4,872,230	4,620,279	4,368,328	4,116,376	3,864,425	3,612,474	3,360,523	3,108,571
9		**Revenue Requirement**											
10		Return on Rate Base		331,640	317,963	302,329	286,695	271,061	255,427	239,793	224,159	208,525	192,891
11		O&M		82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000
12		Municipal Taxes		32,090	32,090	32,090	32,090	32,090	32,090	32,090	32,090	32,090	32,090
13		Deprecation		251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951
14		Taxes		100,030	46,584	49,896	52,831	55,411	57,657	59,589	61,226	62,586	63,686
15		Revenue Requirement		797,711	730,588	718,267	705,568	692,513	679,125	665,423	651,427	637,153	622,618
16		**Revenue**											
17		RNG Injection Revenue		757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
18		**Sufficiency / (Deficiency)**		**(40,711)**	**26,412**	**38,733**	**51,432**	**64,487**	**77,875**	**91,577**	**105,573**	**119,847**	**134,382**

RNG INJECTION
Revenue and Revenue Requirement

Line No.		Col. 1 Description	Col. 13 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
1		Capital										
2		**Rate Base**										
3		Balance, beginning	2,982,596	2,730,645	2,478,693	2,226,742	1,974,791	1,722,840	1,470,888	1,218,937	966,986	715,035
4	+	Additions										
5	+	Working Capital Additions	0	0	0	0	0	0	0	0	0	0
6	-	Depreciation	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)
7		Balance, ending	2,730,645	2,478,693	2,226,742	1,974,791	1,722,840	1,470,888	1,218,937	966,986	715,035	463,083
8		Average Rate Base	2,856,620	2,604,669	2,352,718	2,100,766	1,848,815	1,596,864	1,344,913	1,092,961	841,010	589,059
9		**Revenue Requirement**										
10		Return on Rate Base	177,257	161,623	145,990	130,356	114,722	99,088	83,454	67,820	52,186	36,552
11		O&M	82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000
12		Municipal Taxes	32,090	32,090	32,090	32,090	32,090	32,090	32,090	32,090	32,090	32,090
13		Deprecation	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951
14		Taxes	64,540	65,164	65,572	65,777	65,790	65,624	65,288	64,794	64,150	63,366
15		Revenue Requirement	607,839	592,829	577,603	562,174	546,553	530,753	514,783	498,655	482,377	465,960
16		**Revenue**										
17		RNG Injection Revenue	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
18		**Sufficiency / (Deficiency)**	**149,161**	**164,171**	**179,397**	**194,826**	**210,447**	**226,247**	**242,217**	**258,345**	**274,623**	**291,040**

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Issue 2 – Cost Consequences

Ref: Exhibit B / Tab 1 / Schedule 1 / Appendix 11 Pages 2-6

Preamble: Enbridge asserts that the DCF analysis approved by the Board for Natural Gas Distribution System Expansion Projects under the E.B.O. 188 Guidelines should be applied to the RNG BMS, Injection and GESP Projects. Energy Probe wishes to compare and understand this analogy in more detail.

a) Specifically tabulate and compare the input assumptions for each of the GESP and CE Projects

b) Please provide a revised analysis for the GESP Loop Project in Appendix 11, using the same assumptions as the hypothetical CE Project. Please provide a revised revenue requirement schedule similar to Appendix 12.

RESPONSE

a) Please see the table below. The table shows a comparison between the GES input assumptions and a CE project input assumptions. There are 2 key drivers of the difference: 1) the use of fully allocated costs in the original example versus incremental costs in the CE example 2) No municipal taxes are assumed as most of the GES installations are expected to be on private property

   The table shows that the resulting PI of using the CE inputs is 1.13 versus 1.10. The calculation used marginal costs as opposed to fully allocated costs. Municipal taxes were however not considered for the reasons stated above.

Input Assumptions	Community Expansion Project	Geothermal Energy Service Program	Geothermal Energy Service Program (using CE inputs)
Economic Feasibility Horizon	Residential - 40 Years Large Volume - 20 Years	40 Years	40 Years
Customer Addition Forecast	10 Years	10 Years	10 Years
Customer Revenue Horizon	Various - ends at 40 years for residential and 20 for large volume customers	30 Years	30 Years
Cost Basis	Incremental	Fully Allocated	Incremental
Feasibility Parameters:			
Revenue Rate	QRAM	Fixed Monthly Rate	Fixed Monthly rate
Discount Rate (after-tax weighted average cost of capital)	5.41% (2017 OEB approved capital parameters)	5.43% (current OEB approved capital parameters)	5.43% (current OEB approved capital parameters)
CCA Rate	6%	50%	50%
Income Tax Rate	26.50%	26.50%	26.50%
Municipal Tax Rate	10 Yr. municipal exemption (field estimate thereafter)	0.00%	0.00%
Inflation assumption:			
Revenue	0%	0%	0%
O&M	0%	0%	0%
PI	1.00	1.10	1.13

b) Please see Attachments 1 and 2 to this response.

ATTACHMENT 1

GEOTHERMAL

ECONOMIC FEASIBILITY

Geothermal
Economic Feasibility
Parameters and Results

Line No.	Col. 1 Description	Col. 2
FEASIBILITY PARAMETERS		
1.	Discount Rate	5.43%
2.	CCA Rate	50.00%
3.	Income Tax Rate	26.50%
4.	Customer Revenue Horizon (Years)	30
5.	Capital Investment (Dollars)	
6.	Geothermal Loops	232,050,640
7.	Total Capital Investment	232,050,640
8.	Working Capital (Days of Revenue)	30
FEASIBILITY RESULTS		
9.	Net Present Value (Dollars)	21,377,670
10.	Profitability Index	1.13

Geothermal
Economic Feasibility - 40 year Horizon
DCF Analysis

Line No.	Description	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
	Discount factors to project outset		0.9739	0.9237	0.8762	0.8310	0.7882	0.7476	0.7091	0.6726	0.6379	0.6051	0.5739
	INCREMENTAL CAPITAL INVESTMENT												
1.	Geothermal Loops		(2,540,161)	(4,165,444)	(5,906,810)	(9,741,982)	(15,954,941)	(28,797,566)	(41,235,934)	(41,235,934)	(41,235,934)	(41,235,934)	-
2.	Contribution In Aid Of Construction		-	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital		(2,540,161)	(4,165,444)	(5,906,810)	(9,741,982)	(15,954,941)	(28,797,566)	(41,235,934)	(41,235,934)	(41,235,934)	(41,235,934)	-
4.	Working Capital		(8,524)	(23,566)	(36,602)	(58,664)	(98,274)	(173,484)	(273,764)	(322,902)	(322,902)	(322,902)	(161,451)
5.	Total Investment		(2,548,685)	(4,189,010)	(5,943,412)	(9,800,646)	(16,053,215)	(28,971,050)	(41,509,699)	(41,558,836)	(41,558,836)	(41,558,836)	(161,451)
6.	PV Of Total Investment At Project Outset		(2,482,173)	(3,869,541)	(5,207,340)	(8,144,544)	(12,653,369)	(21,659,100)	(29,434,575)	(27,951,402)	(26,511,581)	(25,145,927)	(92,657)
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**		(2,482,173)	(6,351,714)	(11,559,054)	(19,703,598)	(32,356,967)	(54,016,067)	(83,450,642)	(111,402,044)	(137,913,625)	(163,059,552)	(163,152,209)
	CCA TAX SHIELD												
8.	CCA Tax Shield		166,950	524,388	924,650	1,491,562	2,435,962	4,161,257	6,685,835	8,765,649	9,805,555	10,325,509	7,874,120
9.	PV Of CCA Tax Shield At Project Outset		162,593	484,396	810,135	1,239,520	1,920,059	3,111,005	4,740,933	5,895,549	6,255,247	6,247,636	4,518,958
10.	**ACCUMULATED PV OF CCA TAX SHIELD**		162,593	646,989	1,457,124	2,696,644	4,616,704	7,727,709	12,468,642	18,364,192	24,619,439	30,867,075	35,386,033
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)												
11.	Geothermal Revenues		102,286	385,075	824,302	1,528,267	2,707,560	4,789,373	8,074,546	11,949,365	15,824,184	19,699,003	21,636,413
12.	O&M Expenses		(1,330,334)	(1,063,142)	(1,163,294)	(1,566,458)	(1,914,065)	(2,631,384)	(3,385,320)	(3,577,034)	(3,763,848)	(3,950,662)	(1,343,194)
13.	Net Operating Cash (Before Taxes)		(1,228,048)	(678,067)	(338,992)	(38,191)	793,495	2,157,989	4,689,226	8,372,331	12,060,336	15,748,341	20,293,219
14.	PV of Net Operating Cash (Before Taxes) At Project Outset		(1,196,000)	(626,355)	(297,009)	(31,738)	625,444	1,613,338	3,325,136	5,631,014	7,693,637	9,528,820	11,646,281
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**		(1,196,000)	(1,822,356)	(2,119,365)	(2,151,102)	(1,525,658)	87,680	3,412,816	9,043,830	16,737,466	26,266,286	37,912,567
	TAXES												
16.	Income Tax (Before Interest Tax Shield)		325,433	179,688	89,833	10,121	(210,276)	(571,867)	(1,242,645)	(2,218,668)	(3,195,989)	(4,173,310)	(5,377,703)
17.	Municipal Tax		-	-	-	-	-	-	-	-	-	-	-
18.	Total Taxes		325,433	179,688	89,833	10,121	(210,276)	(571,867)	(1,242,645)	(2,218,668)	(3,195,989)	(4,173,310)	(5,377,703)
19.	PV of Total Taxes At Project Outset		316,940	165,984	78,707	8,410	(165,743)	(427,535)	(881,161)	(1,492,219)	(2,038,814)	(2,525,137)	(3,086,264)
20.	**ACCUMULATED PV OF TOTAL TAXES**		316,940	482,924	561,632	570,042	404,299	(23,235)	(904,396)	(2,396,615)	(4,435,429)	(6,960,566)	(10,046,830)
	ACCUMULATED NPV AND PI												
21.	Net Present Value		(3,198,641)	(7,044,157)	(11,659,662)	(18,588,014)	(28,861,622)	(46,223,913)	(68,473,580)	(86,390,637)	(100,992,149)	(112,886,757)	(99,900,439)
22.	Profitability Index		(0.289)	(0.109)	(0.009)	0.057	0.108	0.144	0.179	0.225	0.268	0.308	0.388

Geothermal
Economic Feasibility - 40 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 13 Year 12	Col. 14 Year 13	Col. 15 Year 14	Col. 16 Year 15	Col. 17 Year 16	Col. 18 Year 17	Col. 19 Year 18	Col. 20 Year 19	Col. 21 Year 20	Col. 22 Year 21
	Discount factors to project outset	0.5443	0.5163	0.4897	0.4645	0.4406	0.4179	0.3963	0.3759	0.3566	0.3382
	INCREMENTAL CAPITAL INVESTMENT										
1.	Geothermal Loops	-	-	-	-	-	-	-	-	-	-
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	-	-	-	-	-	-	-	-	-
5.	Total Investment	-	-	-	-	-	-	-	-	-	-
6.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)
	CCA TAX SHIELD										
8.	CCA Tax Shield	3,937,060	1,968,530	984,265	492,132	246,066	123,033	61,517	30,758	15,379	7,690
9.	PV Of CCA Tax Shield At Project Outset	2,143,090	1,016,348	481,997	228,584	108,405	51,410	24,381	11,563	5,483	2,601
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	37,529,123	38,545,471	39,027,468	39,256,053	39,364,457	39,415,868	39,440,249	39,451,811	39,457,295	39,459,895
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)										
11.	Geothermal Revenues	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413
12.	O&M Expenses	(1,327,094)	(1,327,094)	(1,327,094)	(1,327,094)	(1,435,276)	(1,435,276)	(1,435,276)	(1,435,276)	(1,435,276)	(1,435,276)
13.	Net Operating Cash (Before Taxes)	20,309,319	20,309,319	20,309,319	20,309,319	20,201,137	20,201,137	20,201,137	20,201,137	20,201,137	20,201,137
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	11,055,126	10,485,659	9,945,526	9,433,216	8,899,637	8,441,202	8,006,383	7,593,961	7,202,784	6,831,757
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	48,967,693	59,453,353	69,398,879	78,832,095	87,731,732	96,172,935	104,179,317	111,773,278	118,976,063	125,807,820
	TAXES										
16.	Income Tax (Before Interest Tax Shield)	(5,381,970)	(5,381,970)	(5,381,970)	(5,381,970)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)
17.	Municipal Tax	-	-	-	-	-	-	-	-	-	-
18.	Total Taxes	(5,381,970)	(5,381,970)	(5,381,970)	(5,381,970)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)
19.	PV of Total Taxes At Project Outset	(2,929,608)	(2,778,700)	(2,635,564)	(2,499,802)	(2,358,404)	(2,236,919)	(2,121,691)	(2,012,400)	(1,908,738)	(1,810,416)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(12,976,439)	(15,755,138)	(18,390,703)	(20,890,505)	(23,248,909)	(25,485,828)	(27,607,519)	(29,619,919)	(31,528,657)	(33,339,072)
	ACCUMULATED NPV AND PI										
21.	Net Present Value	(89,631,831)	(80,908,524)	(73,116,565)	(65,954,566)	(59,304,929)	(53,049,234)	(47,140,162)	(41,547,038)	(36,247,508)	(31,223,566)
22.	Profitability Index	0.451	0.504	0.552	0.596	0.637	0.675	0.711	0.745	0.778	0.809

Geothermal
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Line No.	Col. 1 Description	Col. 23 Year 22	Col. 24 Year 23	Col. 25 Year 24	Col. 26 Year 25	Col. 27 Year 26	Col. 28 Year 27	Col. 29 Year 28	Col. 30 Year 29	Col. 31 Year 30	Col. 32 Year 31
	Discount factors to project outset	0.3208	0.3042	0.2886	0.2737	0.2596	0.2462	0.2336	0.2215	0.2101	0.1993
	INCREMENTAL CAPITAL INVESTMENT										
1.	Geothermal Loops	-	-	-	-	-	-	-	-	-	-
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-
4.	Working Capital	-	-	-	-	-	-	-	-	-	8,524
5.	Total Investment	-	-	-	-	-	-	-	-	-	8,524
6.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	1,699
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,152,209)	(163,150,510)
	CCA TAX SHIELD										
8.	CCA Tax Shield	3,845	1,922	961	481	240	120	60	30	15	8
9.	PV Of CCA Tax Shield At Project Outset	1,233	585	277	132	62	30	14	7	3	1
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	39,461,129	39,461,713	39,461,991	39,462,122	39,462,185	39,462,214	39,462,228	39,462,235	39,462,238	39,462,240
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)										
11.	Geothermal Revenues	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,534,127
12.	O&M Expenses	(1,435,276)	(1,435,276)	(1,435,276)	(1,435,276)	(1,435,276)	(1,435,276)	(1,435,276)	(1,435,276)	(1,435,276)	(1,429,833)
13.	Net Operating Cash (Before Taxes)	20,201,137	20,201,137	20,201,137	20,201,137	20,201,137	20,201,137	20,201,137	20,201,137	20,201,137	20,104,294
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	6,479,843	6,146,056	5,829,463	5,529,178	5,244,361	4,974,216	4,717,986	4,474,955	4,244,443	4,006,506
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	132,287,663	138,433,718	144,263,181	149,792,359	155,036,720	160,010,935	164,728,921	169,203,876	173,448,319	177,454,825
	TAXES										
16.	Income Tax (Before Interest Tax Shield)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,327,638)
17.	Municipal Tax	-	-	-	-	-	-	-	-	-	-
18.	Total Taxes	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,353,301)	(5,327,638)
19.	PV of Total Taxes At Project Outset	(1,717,158)	(1,628,705)	(1,544,808)	(1,465,232)	(1,389,756)	(1,318,167)	(1,250,266)	(1,185,863)	(1,124,777)	(1,061,724)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(35,056,231)	(36,684,935)	(38,229,743)	(39,694,975)	(41,084,731)	(42,402,898)	(43,653,164)	(44,839,027)	(45,963,805)	(47,025,529)
	ACCUMULATED NPV AND PI										
21.	Net Present Value	(26,459,648)	(21,941,713)	(17,656,780)	(13,592,703)	(9,738,035)	(6,081,957)	(2,614,223)	674,875	3,794,544	6,741,026
22.	Profitability Index	0.838	0.866	0.892	0.917	0.940	0.963	0.984	1.004	1.023	1.041

Geothermal
Economic Feasibility - 40 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 33 Year 32	Col. 34 Year 33	Col. 35 Year 34	Col. 36 Year 35	Col. 37 Year 36	Col. 38 Year 37	Col. 39 Year 38	Col. 40 Year 39	Col. 41 Year 40
	Discount factors to project outset	0.1890	0.1793	0.1700	0.1613	0.1530	0.1451	0.1376	0.1305	0.1255
	INCREMENTAL CAPITAL INVESTMENT									
1.	Geothermal Loops	-	-	-	-	-	-	-	-	-
2.	Contribution In Aid Of Construction	-	-	-	-	-	-	-	-	-
3.	Net Investment Capital	-	-	-	-	-	-	-	-	-
4.	Working Capital	23,566	36,602	58,664	98,274	173,484	273,764	322,902	322,902	322,902
5.	Total Investment	23,566	36,602	58,664	98,274	173,484	273,764	322,902	322,902	322,902
6.	PV Of Total Investment At Project Outset	4,454	6,562	9,976	15,851	26,540	39,723	44,440	42,151	40,511
7.	**ACCUMULATED PV OF TOTAL INVESTMENT**	(163,146,056)	(163,139,494)	(163,129,518)	(163,113,667)	(163,087,128)	(163,047,404)	(163,002,965)	(162,960,814)	**(162,920,303)**
	CCA TAX SHIELD									
8.	CCA Tax Shield	4	2	1	0	0	0	0	0	0
9.	PV Of CCA Tax Shield At Project Outset	1	0	0	0	0	0	0	0	0
10.	**ACCUMULATED PV OF CCA TAX SHIELD**	39,462,240	39,462,241	39,462,241	39,462,241	39,462,241	39,462,241	39,462,241	39,462,241	**39,462,241**
	INCREMENTAL OPERATING CASHFLOWS (BEFORE TAXES)									
11.	Geothermal Revenues	21,251,338	20,812,111	20,108,146	18,928,853	16,847,040	13,561,867	9,687,048	5,812,229	1,937,410
12.	O&M Expenses	(1,414,785)	(1,391,413)	(1,353,953)	(1,291,200)	(1,180,422)	(1,005,610)	(799,422)	(593,234)	(245,070)
13.	Net Operating Cash (Before Taxes)	19,836,553	19,420,699	18,754,193	17,637,653	15,666,618	12,556,257	8,887,626	5,218,995	1,692,340
14.	PV of Net Operating Cash (Before Taxes) At Project Outset	3,749,515	3,481,816	3,189,124	2,844,761	2,396,693	1,821,920	1,223,170	681,271	212,322
15.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	181,204,340	184,686,156	187,875,280	190,720,041	193,116,734	194,938,654	196,161,824	196,843,095	**197,055,417**
	TAXES									
16.	Income Tax (Before Interest Tax Shield)	(5,256,686)	(5,146,485)	(4,969,861)	(4,673,978)	(4,151,654)	(3,327,408)	(2,355,221)	(1,383,034)	(448,470)
17.	Municipal Tax	-	-	-	-	-	-	-	-	-
18.	Total Taxes	(5,256,686)	(5,146,485)	(4,969,861)	(4,673,978)	(4,151,654)	(3,327,408)	(2,355,221)	(1,383,034)	(448,470)
19.	PV of Total Taxes At Project Outset	(993,622)	(922,681)	(845,118)	(753,862)	(635,124)	(482,809)	(324,140)	(180,537)	(56,265)
20.	**ACCUMULATED PV OF TOTAL TAXES**	(48,019,150)	(48,941,831)	(49,786,949)	(50,540,811)	(51,175,934)	(51,658,743)	(51,982,883)	(52,163,420)	**(52,219,686)**
	ACCUMULATED NPV AND PI									
21.	Net Present Value	9,501,375	12,067,072	14,421,054	16,527,804	18,315,913	19,694,747	20,638,217	21,181,102	**21,377,670**
22.	Profitability Index	1.058	1.074	1.088	1.101	1.112	1.121	1.127	1.130	**1.131**

Geothermal
Revenue and Revenue Requirement

Line No.	Col. 1 Description	Col. 2 Year 1	Col. 3 Year 2	Col. 4 Year 3	Col. 5 Year 4	Col. 6 Year 5	Col. 7 Year 6	Col. 8 Year 7	Col. 9 Year 8	Col. 10 Year 9	Col. 11 Year 10	Col. 12 Year 11
1	Number of Customers	170	300	430	740	1,220	2,240	3,220	3,220	3,220	3,220	
2	Number of Cumulative Customers [50% Effective]	85	320	685	1,270	2,250	3,980	6,710	9,930	13,150	16,370	17,980
3	Number of Tonnes per Customer	4	4	4	4	4	4	4	4	4	4	4
4	Total Number of Tonnes	340	1,280	2,740	5,080	9,000	15,920	26,840	39,720	52,600	65,480	71,920
5	Capital	2,540,161	4,165,444	5,906,810	9,741,982	15,954,941	28,797,566	41,235,934	41,235,934	41,235,934	41,235,934	
6	**Rate Base**											
7	Balance, beginning	0	2,506,348	6,541,262	12,162,707	21,380,573	36,422,726	63,636,838	102,222,375	139,482,517	175,368,128	209,879,208
8	+ Additions	2,540,161	4,165,444	5,906,810	9,741,982	15,954,941	28,797,566	41,235,934	41,235,934	41,235,934	41,235,934	
9	+ Working Capital Additions	8,524	23,566	36,602	58,664	98,274	173,484	273,764	322,902	322,902	322,902	161,451
10	- Depreciation	(42,336)	(154,096)	(321,967)	(582,780)	(1,011,062)	(1,756,937)	(2,924,162)	(4,298,693)	(5,673,225)	(7,047,756)	(7,735,021)
11	Balance, ending	2,506,348	6,541,262	12,162,707	21,380,573	36,422,726	63,636,838	102,222,375	139,482,517	175,368,128	209,879,208	202,305,638
12	Average Rate Base	1,253,174	4,523,805	9,351,985	16,771,640	28,901,649	50,029,782	82,929,607	120,852,446	157,425,323	192,623,668	206,092,423
13	**Revenue Requirement**											
14	Return on Rate Base	77,761	280,709	580,304	1,040,704	1,793,389	3,104,420	5,145,902	7,499,068	9,768,468	11,952,576	12,788,332
15	O&M	1,330,334	1,063,142	1,163,294	1,566,458	1,914,065	2,631,384	3,385,320	3,577,034	3,763,848	3,950,662	1,343,194
16	Municipal Taxes	-	-	-	-	-	-	-	-	-	-	-
17	Deprecation	42,336	154,096	321,967	582,780	1,011,062	1,756,937	2,924,162	4,298,693	5,673,225	7,047,756	7,735,021
18	Taxes	(197,042)	(604,339)	(1,031,230)	(1,620,667)	(2,607,548)	(4,435,842)	(7,060,319)	(8,945,467)	(9,431,757)	(9,226,900)	(5,484,437)
19	Revenue Requirement	1,253,388	893,608	1,034,334	1,569,276	2,110,968	3,056,900	4,395,064	6,429,329	9,773,783	13,724,093	16,382,109
20	**Revenue**											
21	Revenue per Tonne per Month	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07
22	Geothermal Revenue	102,286	385,075	824,302	1,528,267	2,707,560	4,789,373	8,074,546	11,949,365	15,824,184	19,699,003	21,636,413
23	**Sufficiency / (Deficiency)**	**(1,151,103)**	**(508,533)**	**(210,033)**	**(41,009)**	**596,592**	**1,732,473**	**3,679,481**	**5,520,036**	**6,050,401**	**5,974,910**	**5,254,304**

Geothermal
Revenue and Revenue Requirement

Line No.	Description	Col. 1	Col. 13 Year 12	Col. 14 Year 13	Col. 15 Year 14	Col. 16 Year 15	Col. 17 Year 16	Col. 18 Year 17	Col. 19 Year 18	Col. 20 Year 19	Col. 21 Year 20	Col. 22 Year 21
1	Number of Customers											
2	Number of Cumulative Customers [50% Effective]		17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980
3	Number of Tonnes per Customer		4	4	4	4	4	4	4	4	4	4
4	Total Number of Tonnes		71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920
5	Capital											
6	**Rate Base**											
7	Balance, beginning		202,305,638	194,570,616	186,835,595	179,100,574	171,365,552	163,630,531	155,895,510	148,160,488	140,425,467	132,690,446
8	+ Additions											
9	+ Working Capital Additions		0	0	0	0	0	0	0	0	0	0
10	- Depreciation		(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)
11	Balance, ending		194,570,616	186,835,595	179,100,574	171,365,552	163,630,531	155,895,510	148,160,488	140,425,467	132,690,446	124,955,425
12	Average Rate Base		198,438,127	190,703,106	182,968,084	175,233,063	167,498,042	159,763,020	152,027,999	144,292,978	136,557,957	128,822,935
13	**Revenue Requirement**											
14	Return on Rate Base		12,313,372	11,833,402	11,353,433	10,873,464	10,393,495	9,913,525	9,433,556	8,953,587	8,473,618	7,993,649
15	O&M		1,327,094	1,327,094	1,327,094	1,327,094	1,435,276	1,435,276	1,435,276	1,435,276	1,435,276	1,435,276
16	Municipal Taxes		-	-	-	-	-	-	-	-	-	-
17	Deprecation		7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021
18	Taxes		(218,509)	2,368,192	3,615,756	4,193,753	4,436,966	4,512,786	4,504,911	4,455,188	4,384,540	4,303,431
19	Revenue Requirement		21,156,977	23,263,709	24,031,304	24,129,332	24,000,757	23,596,609	23,108,764	22,579,072	22,028,455	21,467,376
20	**Revenue**											
21	Revenue per Tonne per Month		$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07
22	Geothermal Revenue		21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413
23	**Sufficiency / (Deficiency)**		**479,435**	**(1,627,296)**	**(2,394,892)**	**(2,492,919)**	**(2,364,345)**	**(1,960,196)**	**(1,472,351)**	**(942,659)**	**(392,042)**	**169,036**

Geothermal
Revenue and Revenue Requirement

Line No.	Col. 1 Description	Col. 23 Year 22	Col. 24 Year 23	Col. 25 Year 24	Col. 26 Year 25	Col. 27 Year 26	Col. 28 Year 27	Col. 29 Year 28	Col. 30 Year 29	Col. 31 Year 30	Col. 32 Year 31
1	Number of Customers										
2	Number of Cumulative Customers [50% Effective]	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,895
3	Number of Tonnes per Customer	4	4	4	4	4	4	4	4	4	4
4	Total Number of Tonnes	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,580
5	Capital										
6	**Rate Base**										
7	Balance, beginning	124,955,425	117,220,403	109,485,382	101,750,361	94,015,339	86,280,318	78,545,297	70,810,275	63,075,254	55,340,233
8	+ Additions										
9	+ Working Capital Additions	0	0	0	0	0	0	0	0	0	(8,524)
10	- Depreciation	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,735,021)	(7,692,685)
11	Balance, ending	117,220,403	109,485,382	101,750,361	94,015,339	86,280,318	78,545,297	70,810,275	63,075,254	55,340,233	47,639,024
12	Average Rate Base	121,087,914	113,352,893	105,617,871	97,882,850	90,147,829	82,412,807	74,677,786	66,942,765	59,207,743	51,489,628
13	**Revenue Requirement**										
14	Return on Rate Base	7,513,679	7,033,710	6,553,741	6,073,772	5,593,803	5,113,833	4,633,864	4,153,895	3,673,926	3,195,006
15	O&M	1,435,276	1,435,276	1,435,276	1,435,276	1,435,276	1,435,276	1,435,276	1,435,276	1,435,276	1,429,833
16	Municipal Taxes	-	-	-	-	-	-	-	-	-	-
17	Deprecation	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,735,021	7,692,685
18	Taxes	4,217,091	4,128,135	4,037,871	3,946,954	3,855,709	3,764,301	3,672,812	3,581,281	3,489,730	3,383,105
19	Revenue Requirement	20,901,067	20,332,142	19,761,909	19,191,022	18,619,809	18,048,431	17,476,973	16,905,473	16,333,953	15,700,629
20	**Revenue**										
21	Revenue per Tonne per Month	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07
22	Geothermal Revenue	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,534,127
23	**Sufficiency / (Deficiency)**	**735,346**	**1,304,271**	**1,874,504**	**2,445,391**	**3,016,604**	**3,587,981**	**4,159,440**	**4,730,940**	**5,302,460**	**5,833,498**

Geothermal
Revenue and Revenue Requirement

Line No.	Col. 1 Description	Col. 33 Year 32	Col. 34 Year 33	Col. 35 Year 34	Col. 36 Year 35	Col. 37 Year 36	Col. 38 Year 37	Col. 39 Year 38	Col. 40 Year 39	Col. 41 Year 40
1	Number of Customers									
2	Number of Cumulative Customers [50% Effective]	17,660	17,295	16,710	15,730	14,000	11,270	8,050	4,830	1,610
3	Number of Tonnes per Customer	4	4	4	4	4	4	4	4	4
4	Total Number of Tonnes	70,640	69,180	66,840	62,920	56,000	45,080	32,200	19,320	6,440
5	Capital									
6	**Rate Base**									
7	Balance, beginning	47,639,024	40,034,532	32,584,876	25,373,971	18,551,738	12,400,169	7,315,546	3,556,316	1,171,618
8	+ Additions									
9	+ Working Capital Additions	(23,566)	(36,602)	(58,664)	(98,274)	(173,484)	(273,764)	(322,902)	(322,902)	(322,902)
10	- Depreciation	(7,580,925)	(7,413,054)	(7,152,241)	(6,723,959)	(5,978,084)	(4,810,859)	(3,436,328)	(2,061,797)	(687,266)
11	Balance, ending	40,034,532	32,584,876	25,373,971	18,551,738	12,400,169	7,315,546	3,556,316	1,171,618	161,451
12	Average Rate Base	43,836,778	36,309,704	28,979,423	21,962,854	15,475,953	9,857,857	5,435,931	2,363,967	666,534
13	**Revenue Requirement**									
14	Return on Rate Base	2,720,135	2,253,069	1,798,215	1,362,827	960,305	611,694	337,307	146,688	41,359
15	O&M	1,414,785	1,391,413	1,353,953	1,291,200	1,180,422	1,005,610	799,422	593,234	245,070
16	Municipal Taxes	-	-	-	-	-	-	-	-	-
17	Deprecation	7,580,925	7,413,054	7,152,241	6,723,959	5,978,084	4,810,859	3,436,328	2,061,797	687,266
18	Taxes	3,252,217	3,102,585	2,921,772	2,684,292	2,338,576	1,851,230	1,303,302	771,355	255,680
19	Revenue Requirement	14,968,062	14,160,122	13,226,181	12,062,278	10,457,387	8,279,393	5,876,359	3,573,073	1,229,375
20	**Revenue**									
21	Revenue per Tonne per Month	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07
22	Geothermal Revenue	21,251,338	20,812,111	20,108,146	18,928,853	16,847,040	13,561,867	9,687,048	5,812,229	1,937,410
23	**Sufficiency / (Deficiency)**	**6,283,275**	**6,651,990**	**6,881,965**	**6,866,575**	**6,389,653**	**5,282,474**	**3,810,689**	**2,239,156**	**708,034**

ENERGY PROBE INTERROGATORY #9

INTERROGATORY

Issue 2 – Cost Consequences

Ref: Exhibit B / Tab 1 / Schedule 1 / Appendix 10

Preamble: Energy Probe would like to understand the proposed rate design for Rate 401 Renewable Natural Gas Injection Service and compare this to the equivalent rate design for Ontario produced natural gas injection.

a) Please provide an Illustrative example of the services fee/rate calculation based on a cost-of-service calculation of the company's fully-allocated direct and indirect costs using the company's weighted average cost of capital ("WACC") of providing the services under the agreement for a period of time agreed to between the company and the producer.

b) Please Indicate the Ontario Production equivalent rate to Rate 401 and provide a comparable rate design calculation for the same volume of Ontario natural gas production.

RESPONSE

a) Enbridge does not have a rate that would be applicable to the injection of natural gas produced in Ontario into its gas distribution system. For further details please see the Company's response to Energy Probe Interrogatory #3, part b) filed at Exhibit I.1.EGDI.EP.2.

b) Please see the Company's response to part a) of above.

ENERGY PROBE INTERROGATORY #10

INTERROGATORY

Issue 2 – Cost Consequences

Ref: Exhibit A Application Para 9

Preamble: EGD requests approval of including the annual sufficiency/deficiency of the programs within Cap and Trade Compliance Obligation Variance Accounts.

a) Please Indicate why this is an appropriate treatment for recovery of the potential cost consequences. Please be specific to each of RNG and GESP.

b) Has EGD undertaken an analysis of GES as a measure under its DSM Framework? If so please provide the analysis and TRC plus result.

c) Please Indicate specifically, if GESP was approved, as a DSM measure, why incentive costs for GESP would not be included in EGD's DSM Programs rather than aap and trade account.

RESPONSE

a) Please see response to Energy Probe Interrogatory #2 filed at Exhibit I.1.EGDI.EP.2.

b) No.

c) The immediate application does not contemplate the Geothermal Energy Service being offered as part of the Company's DSM programs.

ENERGY PROBE INTERROGATORY #11

INTERROGATORY

Issue 2 – Cost Consequences

Ref: Exhibit B / Tab 1 / Schedule 1 / p. 3, # 10

a) Please provide a summary of administrative costs to date (including 2018F) related to RNG Enabling and GESP program development. Specifically breakout the staff resources and legal/regulatory costs related to this application.

b) Please provide 5 year administrative cost projections for the post-implementation period of the programs, if approved, for each of RNG Enabling Service and GESP.

RESPONSE

a) For GES the 2017 FTE count was 0.25, for 2018 the Company forecasts 1 FTE to date which could change pending the outcome of this proceeding.

For RNG please see the response to Board Staff Interrogatory #9 filed at Exhibit I.2.EGDI.STAFF.9

The Company estimates that the combined total resources for both the programs for legal and regulatory were 0.3 FTEs in 2017 and 0.2 FTEs in 2018.

b) The forecasted administrative cost projections for GES are set out in Exhibit B, Tab 1, Schedule 1, Appendix 11, Line 12.

For the RNG enabling program, the Operating and Maintenance costs will be fully allocated to individual projects.

ENWAVE INTERROGATORY #7

INTERROGATORY

Issue 2.3: Are the service fees for the Geothermal Energy Service Program reasonable and appropriate?

Please confirm that in the first year of the Program, gas rate payers will be making a contribution of $7,226,130. Has Enbridge conducted any customer surveys to indicate whether customers are supportive of providing this subsidy? Please provide customer surveys relating to concerns respecting the cost of gas utility services.

RESPONSE

Not confirmed. The revenue and revenue requirement for the Geothermal Energy Service Program is set out at Exhibit B, Tab 1, Schedule 1, Appendix 12. It shows that the largest annual deficiency in the first 10 years is less than $1.5 million. This is relatively modest in the context of a utility with more than 2 million customers. Additionally, there are many years when customers will benefit from a revenue sufficiency. The Company has not performed any surveys about customer reactions.

ENWAVE INTERROGATORY #8

INTERROGATORY

Issue 2.3: Are the service fees for the Geothermal Energy Service Program reasonable and appropriate?

The Board's *Final Report: Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities* (EB2016- 0359) states that "heat pumps are considered a fuel switching initiative and are not comparable to energy efficiency alternatives, and are also currently very high cost compared to other energy efficiency options for space heating" (at pp. 23-24).

Please provide any studies that Enbridge has carried out that compare both the societal costs and benefits and the costs and benefits to Enbridge of pursuing other geothermal program as opposed to other options for space heating.

RESPONSE

Enbridge has not undertaken the studies described in this question.

ENWAVE INTERROGATORY #9

INTERROGATORY

Issue 2.4: What are the appropriate terms and conditions of the Geothermal Energy Service Program?

Please advise whether Enbridge would be willing to have the Board impose the charge that Enbridge is proposing but make the proceeds of those charges available for other providers of geothermal or other Competing Technologies that can also result in carbon abatement.

If Enbridge would not be agreeable, why not?

RESPONSE

Enbridge is not open to sharing the proceeds (sufficiency) from the Geothermal Energy Service program with providers of competing technologies. As described in the pre-filed evidence, Enbridge believes that any such amounts should be credited to its natural gas ratepayers, since this activity is being undertaken as an abatement activity under the Board's Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities.

FRPO INTERROGATORY #2

INTERROGATORY

Issue 2

REF: Exhibit B / Tab 1 / Schedule 1 / p. 15, #44, p. 16, #48, p. 17 # 49, #50 and p.19 #56 and 57
And
EB-2017-0224 Transcript Volume 3, Oral Hearing, 2018 Compliance Plans, 20180426, page 16

Preamble: In the Transcript Reference from EB-2017-0224, Mr. McGill from Enbridge states:

> *MR. McGILL: Yes. Yesterday we received a letter from the Minister of Energy indicating to us that the proposed funding in support of our RNG procurement plan will not be available until after the provincial election in June. And as such, we are putting the procurement RFP on hold for the time being and we're in the process of communicating this information to the parties that have responded to the RFP, so for the time being that process is going to be on hold.*

In addition to Board Staff IR-6, we would like to understand better Enbridge's plans in the short term.

In light of the uncertainty of funding and in the period before a decision is made:

a) What activities will Enbridge undertake in exploring the respective RNG and Geotherm initiatives?
b) Where will the costs of these activities accrue?
c) What is Enbridge's proposed disposition of these costs in the event that funding is not provided and the company chooses not to proceed?

RESPONSE

a) Enbridge's plans to proceed with the abatement initiatives set out in this application are unchanged.

b) The costs associated with the implementation of the Company's RNG Enabling Service programs and its Geothermal Energy Service will accrue to the service recipients for each of these initiatives.

c) If Enbridge does not receive approvals for the abatement initiatives, then it may record appropriate 2018 development costs in the relevant Cap and Trade variance accounts for later review and disposition.

FRPO INTERROGATORY #3

INTERROGATORY

Issue 2

REF: Exhibit B / Tab 1 / Schedule 1 / pp. 21-22 and p. 25, #74

Preamble: In addition to Board Staff IR-10, we would like to understand Enbridge's investment in this area of the market.

Does Enbridge expect to garner offset credits from its investment in these ventures?

a) If so, please describe how Enbridge proposes that would be accomplished.

RESPONSE

No offset credits will be garnered from the upgrading and injection services related to RNG. Offset credits may be possible through the procurement of RNG and subject to all applicable regulations, rules and negotiations with the seller of the RNG product.

FRPO INTERROGATORY #4

INTERROGATORY

Issue 2

REF: Exhibit B / Tab 1 / Schedule 1/ p. 8, #24, p. 10, #30 and p.20, #59

Preamble: We are interested in understanding Enbridge's belief and commitment to these initiatives. On page 20, paragraph 59, Enbridge states:

> "*As detailed in the "Regulatory Treatment of RNG Enabling Service and Geothermal Energy Service Program" section of this evidence, Enbridge is also requesting approval of its proposal to record the annual revenue deficiency or sufficiency associated with the RNG enabling service program in the GHG-Customer VA to be periodically cleared to ratepayers."*

Would Enbridge be willing to accept approval of the proposed construct with no deferral account to accept the risks associated with the uncertainty of the development of the market?

a) If not, why not?
b) If not, please explain why the Board should ask ratepayers to take on that risk?
    i) Please answer the above question recognizing, as stated in evidence, ratepayers contribute to the government funds that may be available to subsidize these projects.

RESPONSE

a) and b) Enbridge is not willing to accept approval of these programs without a variance account. Enbridge believes that the proposed RNG and Geothermal services are properly included within the regulated utility. For further details, please see the Company's response to Board Staff Interrogatory #16 filed at Exhibit I.3.EGDI.STAFF.16 and Energy Probe Interrogatory #2 at Exhibit I.1.EGDI.EP.2.

FRPO INTERROGATORY #5

INTERROGATORY

Issue 2

REF: EB-2017-0255, Exhibit B.FRPO.1 and EB-2017-0255, Exhibit JT1.24 (attached for ref.)

Preamble: We would like to understand better the company's technical views on the inclusion of human and animal waste as biomass given the scientific view of biomass as emission-neutral as pre-scribed by the new regulations.

Please provide Enbridge's technical view of the inclusion of human and agricultural waste combustion as biomass being emission neutral due to the absorption of CO2 as the biomass regrows.

a) Please provide company's technical views how this carbon cycle is sustainable as carbon-neutral with the introduction of human waste-derived RNG being combusted in customers' homes and businesses.

RESPONSE

As per the Ministry of Environment's (MOECC's) Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions, standard quantification method number ON.400, all volumes of natural gas derived from biomass are excluded from the quantification of the GHG emissions from the distribution of natural gas. This means that emissions from RNG do not bear a compliance obligation under the Ontario Cap and Trade program.

Furthermore, the value of RNG in assisting the Province in meeting its GHG reduction targets has been recognized through the Province's Climate Change Action Plan (CCAP).[1] In the CCAP, the Province has committed between $60 million and $100 million to "encourage the use of cleaner, renewable natural gas in the industrial, transportation and building sectors". As stated on page 28 of the CCAP:

> Methane released from sources like landfills, municipal green bin collection, agricultural residues, livestock manure, food and beverage manufacturing waste, sewage treatment plants and forestry waste can be renewed and directly substituted for conventional

[1] Available at: http://www.applications.ene.gov.on.ca/ccap/products/CCAP_ENGLISH.pdf

> natural gas. Renewable natural gas is a low-carbon fuel that does not add new carbon to the atmosphere. It is fully interchangeable with conventional natural gas and uses the same infrastructure.

Enbridge's technical view is aligned with the statement above from the CCAP.

OSEA INTERROGATORY #1

INTERROGATORY

Issue 2.3,

Reference: EB-2017-0319, Exhibit B, Tab 1, Schedule 1, Page 27 of 30.

Preamble: "To calculate the Geothermal Energy Service program service fees, Enbridge has built a DCF model using a 10 year customer forecast, estimates of capital, operating costs and taxes, applying the principles set out in EBO 188.

The Company's 10 year customer forecast is based on several factors including expected demand for geothermal systems (which will be driven in part by a GreenON Fund Geothermal Rebate program), current capacity in the market, and ramp-up capability of the market to meet future demand. The Company expects about 170 customers in Year 1 and over a period of 10 years a total of about 18,000 customers."

a) Please explain how Enbridge determined its customer forecasts for geothermal systems. If there are any reports, documents, workplans, or calculations that support these forecasts please file.

b) Please explain how service rates for the Geothermal Energy Service Program are affected if the customer forecasts change, if at all (i.e., if more than 18,000 customers are interested in installing geothermal systems over the 10 year period, will service fees be lower than currently predicted?)

RESPONSE

a) Please see response to Board Staff Interrogatory #13(b) filed at Exhibit I.2.EGDI.STAFF.13.

b) The service fees may change (be reduced) where the customer additions are higher than forecast. While most of the associated costs are capital costs associated with specific installations, there are some program support costs that are allocable to all geothermal customers. Where the number of customers increases, then the amount allocable to each customer goes down. As explained in response to Board Staff Interrogatory #15(b) (ii) filed at Exhibit I.2.EGDI.STAFF.15, where there are material changes in the Geothermal Energy Service program costs, then Enbridge will present evidence in support of an updated service fee.

OSEA INTERROGATORY #2

INTERROGATORY

Issue 2.3,

Reference: EB-2017-0319, Exhibit B, Tab 1, Schedule 1, Appendix 11, Page 3 of 6; EB-2017-0319, Exhibit B, Tab 1, Schedule 1, Page 27 of 30.

Preamble: Enbridge estimates in its "Geothermal Economic Feasibility – 40 year Horizon DCF Analysis" table that it will cost approximately $2.7 M to install 170 geothermal loops in Year 1. According to that estimate, each geothermal loop will cost on average $15,880 to install.

Enbridge states that "the estimated capital costs for the installation of the geothermal loops are based on unit costs for drilling and trenching based on market information and the Company's experience. The estimated capital costs also include construction management, commissioning and quality assurance with contingencies based on geographical and geological construction uncertainties."

a) Please explain how Enbridge determined the cost to install geothermal loops. If there are any reports, documents, workplans, or calculations that support Enbridge's cost estimate please provide.

RESPONSE

Please see response to Board Staff Interrogatory #14, filed at Exhibit I.2.EGDI.STAFF.14.

SEC INTERROGATORY #16

INTERROGATORY

Issue 2.1

[B-1-1, p.18]

With respect to the RNG Enabling Program:

a. Please provide a copy of the form or template of the contract Enbridge will require the producer to sign.
b. Will Enbridge require the producer to provide some form of guarantee or security (e.g. letter of credit) from a producer who enters into a contract? If yes, please provide details.
c. If not, please explain why not.
d. Is the individual PI of each project required to be at least 1.0, or is it the aggregate of the projects? If it is the latter, please explain the rationale.
e. Is the OM&A included in the DCF calculation done on an incremental or fully allocated basis? Please estimate the annual difference between each type of costing.

RESPONSE

a) A copy of Enbridge's draft Biogas Services Agreement is provided in the response to Board Staff Interrogatory #6 at Exhibit I.2.EGDI.Staff.6.

b) Article 13 of the Biogas Services Agreement addresses financial assurances. The treatment of financial assurances will be consistent with Enbridge's existing practices.

c) See response to part b) above.

d) The minimum PI of each project is required to be at least 1.0.

e) The OM&A included in the DCF calculation is calculated on a fully allocated basis. Recalculating the injection service example using incremental costs results in a decrease of $22,000 per year. The example for upgrading costs was based on contracting for the operations and cannot be differentiated by incremental or fully allocated costs.

SEC INTERROGATORY #17

INTERROGATORY

Issue 2.3

[B-1-1, p.18]

If a current Enbridge natural gas customer decided to sign up for the Geothermal Energy Service, who pays for the stranded costs of assets used to serve that individual property (e.g. gas line on property, meter)?

RESPONSE

When a customer ceases to receive natural gas service (resulting from a customer initiated request), the customer will pay the cut off at main charge. Within the group or pool concept of depreciation resident within natural gas rates, individual assets within a pool are retired both beyond and in advance of their book depreciable life, and the residual net book value of those assets, as well as all other assets within the pool, are recovered from customers through Board approved rates.

SEC INTERROGATORY #18

INTERROGATORY

Issue 2.3

[B1-1-1, p.27]

With respect to the Geothermal Energy Service Program service fees:

a. Is the service fee fixed over the length of the contract term or will it be adjusted? If it will be adjusted, please explain when and how. If it will not be adjusted, please explain why not.
b. Please explain why the service is entirely variable (per tonne of heating capacity).

RESPONSE

a) Please see response to Board Staff Interrogatory #15 (b) (ii), filed at Exhibit I.2.EGDI.STAFF.15.

b) The service fee is variable based on the size of system installed and does not have a fixed and variable component as is the case with current natural gas rates and service fees. The majority of the cost of the system is based on the size of the system installed and O&M is roughly the same for all loops.

SEC INTERROGATORY #19

INTERROGATORY

Issue 2.3

[B1-1-1, p.29]

With respect to the customer additions forecast for the Geothermal Energy Service Program:

a. Please provide the basis for the 10 year customer additions forecast and tonne of heating capacity forecast.
b. If the GreenON funding program is cancelled please provide a revised 10 year customer additions and volume (tonne of heating capacity) forecast.
c. Please provide a revised forecast PI based on the customer addition forecast provided in part (b).

RESPONSE

a) Please see response to Board Staff Interrogatory #13(b), filed at Exhibit I.2.EGDI.STAFF.13.

b) Enbridge's forecasts are based on the continuation of the GreenON rebate program. If that program is cancelled, Enbridge will investigate other sources of customer support, such as from the Federal Government. Without information about what other options might exist, Enbridge is not able to provide a revised forecast.

c) See part (b).

SEC INTERROGATORY #20

INTERROGATORY

Issue 2.3

[B1-1-1, p.21]

With respect to the Geothermal Energy Service Program:

a. Will Enbridge use its own existing resources, hire additional staff, or sub-contract to third parties the installation and maintenance of the geothermal loops? Please explain the rationale of the approach taken.
b. If the response to part (a) in whole or in part is to sub-contract to third parties, does Enbridge expect those agreements to contain any exclusivity or other restraint on trade provisions? If so, please provide details.

RESPONSE

a) and b) Please see response to Board Staff Interrogatory #12(e), filed at Exhibit I.2.EGDI.STAFF.12.

SEC INTERROGATORY #21

INTERROGATORY

Issue 2.4

[B-1-1, p.26, 28]

Enbridge states that it will enter into contract with the homeowner property owner.

a. Please provide a copy of the contact that it will require homeowners to enter into.
b. Please provide details and a rationale regarding the expected term of the contract and its material terms.
c. If not the same as what is provided in response to part (a), please provide a copy of the proposed customer service agreement.
d. Please provide details and a rationale regarding the expected material terms of the proposed customer service agreement.
e. Does Enbridge expect to make changes to its standard Handbook of Rates and Distribution Services and/or Conditions of Service to account for its Geothermal Energy Service Program? If so, please provide details.

RESPONSE

a) to e) Please see response to Board Staff Interrogatory #15 filed at Exhibit I.2.EGDI.STAFF.15.

SEC INTERROGATORY #22

INTERROGATORY

Issue 2.4

[B1-1-1, p.21]

With respect to the Geothermal Energy Service Program:

a. Please provide a breakdown of all the costs for an individual homeowner for installing a geothermal energy system.
b. What is the expected payback period for the homeowner with and without the GreenON/CCAP subsidy? Please provide details of the calculation.
c. Please provide a breakdown of all the costs for Enbridge for each incremental homeowner who participates in the Geothermal Energy System Program.

RESPONSE

a) Please see response to Energy Probe Interrogatory #4(a) filed at Exhibit I.1.EGDI.EP.4.

b) With the GreenON/CCAP subsidy the cost to the homeowner for the heat pump equipment is roughly the same as it would have been for a natural gas furnace and air conditioner package. There is no capital cost to the homeowner for the geothermal loop when using the Geothermal Energy Service program. On the operating cost basis, the costs are comparable as provided in response to Board Staff Interrogatory #10(c) filed at Exhibit I.2.EGDI.STAFF.10. Overall, the customer is held whole.

   Without GreenON/CCAP subsidy, the overall costs to the homeowner will be higher than would be the case for a natural gas furnace and air conditioner package. However, compared to heating oil or propane which are substantially more expensive than natural gas, there are savings.

c) Assuming a 4 tonne system is installed, the average incremental capital cost for Enbridge to add a new construction home customer would be around $13,000. This includes direct capital and indirect costs.

SEC INTERROGATORY #23

INTERROGATORY

Issue 2.4

[B1-1-1, Appendix 11]

With respect to the Geothermal Energy Service Program OM&A costs:

a. Please provide a breakdown of the OM&A costs of the program.
b. Is the OM&A included in the DCF calculation done on an incremental or fully allocated basis? Please estimate the annual difference between each type of costing method.

RESPONSE

a) Please see response to Board Staff Interrogatory #14 filed at Exhibit I.2.EGDI.STAFF.14.

b) The OM&A included in the DCF calculation is done on a fully allocated basis. The annual OM&A difference between fully allocated and non-fully allocated cost basis for the Geothermal Energy Service program is as follows:

Year 1 – 3 => $208,000
Year 4 – 10 => $256,000
Year 10+ => $87,000

SEC INTERROGATORY #24

INTERROGATORY

Issue 2.4

[B-1-1, Appendices)]

Please provide a copy of the DCF analyses included in the evidence in Excel format with the formulas intact.

RESPONSE

The Company declines to provide an electronic version of the Excel models as they are considered proprietary, intellectual property. Further, the models which were used in the production of the evidence are linked to various other sources, working and reference files which contain extensive data and calculations. Provision of this model to a third party for the purpose of recalculating DCF results would be counterproductive as the Company would have no means by which to verify that the third party had completed their calculations correctly. The same reasoning applies equally to other live spreadsheets that are requested in other interrogatories in this proceeding.

SEC INTERROGATORY #25

INTERROGATORY

Issue 2.4

[B1-1-1, Appendix 9]

With respect to Rate 400 and Rate 401, please provide a copy of the terms and conditions of service.

RESPONSE

A copy of Enbridge's draft Biogas Services Agreement is provided in the response to Board Staff Interrogatory #6 at Exhibit I.2.EGDI.Staff.6.

SEC INTERROGATORY #26

INTERROGATORY

Issue 2.4

[B1-1-1, p.30]

What would be the annual service fee for the Geothermal Energy Services Program if only customers of this new program were responsible for all costs in all years?

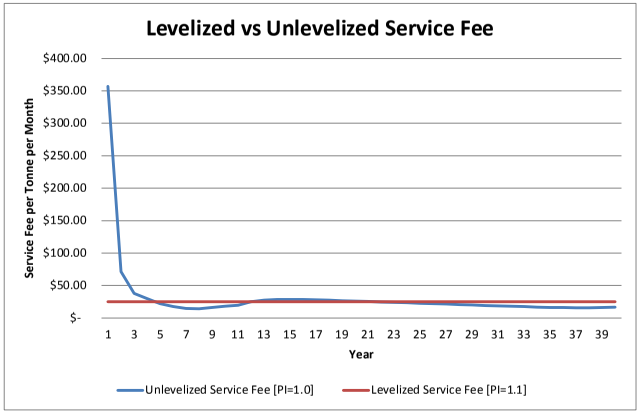
RESPONSE

Please see Attachment 1 to this response. The attachment shows the monthly service fee per tonne if revenue equals revenue requirement. The initial customers would pay a high fee because the startup costs are spread over very few customers.

This form of fee setting is inappropriate and does not promote customer adoption or enable market transformation. The Enbridge proposal applies the Board's existing customer addition model to transform the residential heating market and abate carbon emissions in response to the Company's obligation under the Cap and Trade framework.

Geothermal
Revenue and Revenue Requirement

Line No.		Col. 1 Description	Col. 2 Year 1	Col. 3 Year 2	Col. 4 Year 3	Col. 5 Year 4	Col. 6 Year 5	Col. 7 Year 6	Col. 8 Year 7	Col. 9 Year 8	Col. 10 Year 9	Col. 11 Year 10	Col. 12 Year 11	Col. 13 Year 12	Col. 14 Year 13	Col. 15 Year 14
1		Number of Customers	170	300	430	740	1,220	2,240	3,220	3,220	3,220	3,220				
2		Number of Cumulative Customers [50% Effective]	85	320	685	1,270	2,250	3,980	6,710	9,930	13,150	16,370	17,980	17,980	17,980	17,980
3		Number of Tonnes per Customer	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4		Total Number of Tonnes	340	1,280	2,740	5,080	9,000	15,920	26,840	39,720	52,600	65,480	71,920	71,920	71,920	71,920
5		Capital	2,702,492	4,339,017	6,140,834	10,002,812	16,355,698	29,384,945	42,055,686	42,055,686	42,055,686	42,055,686				
6		**Rate Base**														
7		Balance, beginning	0	2,665,974	6,866,157	12,706,529	22,161,880	37,570,419	65,321,071	104,652,067	142,630,344	179,206,764	214,381,329	206,637,828	198,732,877	190,827,926
8	+	Additions	2,702,492	4,339,017	6,140,834	10,002,812	16,355,698	29,384,945	42,055,686	42,055,686	42,055,686	42,055,686				
9	+	Working Capital Additions	8,524	23,566	36,602	58,664	98,274	173,484	273,764	322,902	322,902	322,902	161,451	0	0	0
10	-	Depreciation	(45,042)	(162,400)	(337,064)	(606,125)	(1,045,433)	(1,807,778)	(2,998,455)	(4,400,311)	(5,802,167)	(7,204,023)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)
11		Balance, ending	2,665,974	6,866,157	12,706,529	22,161,880	37,570,419	65,321,071	104,652,067	142,630,344	179,206,764	214,381,329	206,637,828	198,732,877	190,827,926	182,922,974
12		Average Rate Base	1,332,987	4,766,066	9,786,343	17,434,204	29,866,149	51,445,745	84,986,569	123,641,205	160,918,554	196,794,047	210,509,579	202,685,353	194,780,401	186,875,450
13		**Revenue Requirement**														
14		Return on Rate Base	82,714	295,741	607,257	1,081,817	1,853,238	3,192,283	5,273,539	7,672,115	9,985,228	12,211,354	13,062,422	12,576,918	12,086,404	11,595,891
15		O&M	1,537,880	1,270,689	1,370,840	1,822,089	2,169,696	2,887,015	3,640,951	3,832,665	4,019,479	4,206,293	1,430,529	1,414,429	1,414,429	1,414,429
16		Municipal Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Deprecation	45,042	162,400	337,064	606,125	1,045,433	1,807,778	2,998,455	4,400,311	5,802,167	7,204,023	7,904,951	7,904,951	7,904,951	7,904,951
18		Taxes	(209,419)	(635,210)	(1,074,910)	(1,675,123)	(2,677,364)	(4,534,591)	(7,200,034)	(9,115,638)	(9,608,222)	(9,397,740)	(5,581,352)	(212,198)	2,425,110	3,696,972
19		Revenue Requirement	1,456,216	1,093,620	1,240,251	1,834,909	2,391,003	3,352,484	4,712,910	6,789,453	10,198,652	14,223,931	16,816,551	21,684,100	23,830,894	24,612,243
20		**Revenue**														
21		Revenue per Tonne per Month	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07
22		Geothermal Revenue	102,286	385,075	824,302	1,528,267	2,707,560	4,789,373	8,074,546	11,949,365	15,824,184	19,699,003	21,636,413	21,636,413	21,636,413	21,636,413
23		**Sufficiency / (Deficiency)**	**(1,353,931)**	**(708,545)**	**(415,950)**	**(306,642)**	**316,557**	**1,436,889**	**3,361,636**	**5,159,912**	**5,625,532**	**5,475,073**	**4,819,862**	**(47,688)**	**(2,194,482)**	**(2,975,830)**
		ONLY GES Program customers responsible for all costs in all years [no annual sufficiency / (Deficiency)]														
24		Revenue Requirement	1,456,216	1,093,620	1,240,251	1,834,909	2,391,003	3,352,484	4,712,910	6,789,453	10,198,652	14,223,931	16,816,551	21,684,100	23,830,894	24,612,243
25		Revenue per Tonne per Month	$ 356.92	$ 71.20	$ 37.72	$ 30.10	$ 22.14	$ 17.55	$ 14.63	$ 14.24	$ 16.16	$ 18.10	$ 19.49	$ 25.13	$ 27.61	$ 28.52



	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14
Unlevelized Service Fee [PI=1.0]	$ 356.92	$ 71.20	$ 37.72	$ 30.10	$ 22.14	$ 17.55	$ 14.63	$ 14.24	$ 16.16	$ 18.10	$ 19.49	$ 25.13	$ 27.61	$ 28.52
Levelized Service Fee [PI=1.1]	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07

Geothermal
Revenue and Revenue Requirement

Line No.	Description	Col. 1	Col. 16 Year 15	Col. 17 Year 16	Col. 18 Year 17	Col. 19 Year 18	Col. 20 Year 19	Col. 21 Year 20	Col. 22 Year 21	Col. 23 Year 22	Col. 24 Year 23	Col. 25 Year 24	Col. 26 Year 25	Col. 27 Year 26	Col. 28 Year 27
1	Number of Customers														
2	Number of Cumulative Customers [50% Effective]		17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980	17,980
3	Number of Tonnes per Customer		4	4	4	4	4	4	4	4	4	4	4	4	4
4	Total Number of Tonnes		71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920	71,920
5	Capital														
6	**Rate Base**														
7	Balance, beginning		182,922,974	175,018,023	167,113,071	159,208,120	151,303,168	143,398,217	135,493,265	127,588,314	119,683,363	111,778,411	103,873,460	95,968,508	88,063,557
8	+ Additions														
9	+ Working Capital Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
10	- Depreciation		(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)	(7,904,951)
11	Balance, ending		175,018,023	167,113,071	159,208,120	151,303,168	143,398,217	135,493,265	127,588,314	119,683,363	111,778,411	103,873,460	95,968,508	88,063,557	80,158,605
12	Average Rate Base		178,970,498	171,065,547	163,160,595	155,255,644	147,350,693	139,445,741	131,540,790	123,635,838	115,730,887	107,825,935	99,920,984	92,016,033	84,111,081
13	**Revenue Requirement**														
14	Return on Rate Base		11,105,377	10,614,864	10,124,350	9,633,836	9,143,323	8,652,809	8,162,295	7,671,782	7,181,268	6,690,755	6,200,241	5,709,727	5,219,214
15	O&M		1,414,429	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611	1,522,611
16	Municipal Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
17	Deprecation		7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951	7,904,951
18	Taxes		4,286,112	4,533,890	4,610,987	4,602,745	4,551,832	4,479,584	4,396,668	4,308,419	4,217,503	4,125,253	4,032,337	3,939,087	3,845,670
19	Revenue Requirement		24,710,869	24,576,316	24,162,900	23,664,143	23,122,717	22,559,955	21,986,526	21,407,763	20,826,333	20,243,570	19,660,140	19,076,377	18,492,447
20	**Revenue**														
21	Revenue per Tonne per Month		$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07
22	Geothermal Revenue		21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413	21,636,413
23	**Sufficiency / (Deficiency)**		**(3,074,456)**	**(2,939,903)**	**(2,526,487)**	**(2,027,731)**	**(1,486,304)**	**(923,542)**	**(350,113)**	**228,650**	**810,080**	**1,392,843**	**1,976,273**	**2,560,036**	**3,143,966**
	ONLY GES Program customers responsible for a														
24	Revenue Requirement		24,710,869	24,576,316	24,162,900	23,664,143	23,122,717	22,559,955	21,986,526	21,407,763	20,826,333	20,243,570	19,660,140	19,076,377	18,492,447
25	Revenue per Tonne per Month		$ 28.63	$ 28.48	$ 28.00	$ 27.42	$ 26.79	$ 26.14	$ 25.48	$ 24.81	$ 24.13	$ 23.46	$ 22.78	$ 22.10	$ 21.43

	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Unlevelized Service Fee [PI=1.0]	$ 28.63	$ 28.48	$ 28.00	$ 27.42	$ 26.79	$ 26.14	$ 25.48	$ 24.81	$ 24.13	$ 23.46	$ 22.78	$ 22.10	$ 21.43
Levelized Service Fee [PI=1.1]	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07

Geothermal
Revenue and Revenue Requirement

Line No.	Col. 1 Description	Col. 29 Year 28	Col. 30 Year 29	Col. 31 Year 30	Col. 32 Year 31	Col. 33 Year 32	Col. 34 Year 33	Col. 35 Year 34	Col. 36 Year 35	Col. 37 Year 36	Col. 38 Year 37	Col. 39 Year 38	Col. 40 Year 39	Col. 41 Year 40
1	Number of Customers													
2	Number of Cumulative Customers [50% Effective]	17,980	17,980	17,980	17,895	17,660	17,295	16,710	15,730	14,000	11,270	8,050	4,830	1,610
3	Number of Tonnes per Customer	4	4	4	4	4	4	4	4	4	4	4	4	4
4	Total Number of Tonnes	71,920	71,920	71,920	71,580	70,640	69,180	66,840	62,920	56,000	45,080	32,200	19,320	6,440
5	Capital													
6	**Rate Base**													
7	Balance, beginning	80,158,605	72,253,654	64,348,702	56,443,751	48,575,317	40,809,200	33,204,711	25,847,220	18,889,428	12,618,770	7,438,509	3,610,966	1,185,281
8	+ Additions													
9	+ Working Capital Additions	0	0	0	(8,524)	(23,566)	(36,602)	(58,664)	(98,274)	(173,484)	(273,764)	(322,902)	(322,902)	(322,902)
10	- Depreciation	(7,904,951)	(7,904,951)	(7,904,951)	(7,859,910)	(7,742,551)	(7,567,887)	(7,298,826)	(6,859,518)	(6,097,174)	(4,906,497)	(3,504,641)	(2,102,784)	(700,928)
11	Balance, ending	72,253,654	64,348,702	56,443,751	48,575,317	40,809,200	33,204,711	25,847,220	18,889,428	12,618,770	7,438,509	3,610,966	1,185,281	161,451
12	Average Rate Base	76,206,130	68,301,178	60,396,227	52,509,534	44,692,259	37,006,955	29,525,966	22,368,324	15,754,099	10,028,639	5,524,737	2,398,123	673,366
13	**Revenue Requirement**													
14	Return on Rate Base	4,728,700	4,238,186	3,747,673	3,258,292	2,773,219	2,296,335	1,832,129	1,387,987	977,565	622,291	342,818	148,807	41,783
15	O&M	1,522,611	1,522,611	1,522,611	1,517,168	1,502,120	1,478,748	1,441,288	1,378,535	1,267,757	1,092,946	886,757	680,569	288,738
16	Municipal Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Deprecation	7,904,951	7,904,951	7,904,951	7,859,910	7,742,551	7,567,887	7,298,826	6,859,518	6,097,174	4,906,497	3,504,641	2,102,784	700,928
18	Taxes	3,752,171	3,658,629	3,565,067	3,455,471	3,320,618	3,166,664	2,981,093	2,737,967	2,384,806	1,887,733	1,328,983	786,537	260,687
19	Revenue Requirement	17,908,433	17,324,378	16,740,302	16,090,841	15,338,509	14,509,634	13,553,336	12,364,007	10,727,302	8,509,467	6,063,199	3,718,698	1,292,136
20	**Revenue**													
21	Revenue per Tonne per Month	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07
22	Geothermal Revenue	21,636,413	21,636,413	21,636,413	21,534,127	21,251,338	20,812,111	20,108,146	18,928,853	16,847,040	13,561,867	9,687,048	5,812,229	1,937,410
23	**Sufficiency / (Deficiency)**	**3,727,980**	**4,312,035**	**4,896,111**	**5,443,286**	**5,912,829**	**6,302,477**	**6,554,809**	**6,564,845**	**6,119,738**	**5,052,400**	**3,623,849**	**2,093,531**	**645,273**
	ONLY GES Program customers responsible for a													
24	Revenue Requirement	17,908,433	17,324,378	16,740,302	16,090,841	15,338,509	14,509,634	13,553,336	12,364,007	10,727,302	8,509,467	6,063,199	3,718,698	1,292,136
25	Revenue per Tonne per Month	$ 20.75	$ 20.07	$ 19.40	$ 18.73	$ 18.09	$ 17.48	$ 16.90	$ 16.38	$ 15.96	$ 15.73	$ 15.69	$ 16.04	$ 16.72

	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
Unlevelized Service Fee [PI=1.0]	$ 20.75	$ 20.07	$ 19.40	$ 18.73	$ 18.09	$ 17.48	$ 16.90	$ 16.38	$ 15.96	$ 15.73	$ 15.69	$ 16.04	$ 16.72
Levelized Service Fee [PI=1.1]	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07	$ 25.07