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August 19, 2011

Energy Services Association of Canada Suite 1500, 1055 West Georgia Street Vancouver, B.C. V6E 4N7

Attention: Mr. Karl E. Gustafson, Q.C.

Dear Mr. Gustafson:

Re: FortisBC Energy Utilities¹ ("FEU") 2012 and 2013 Revenue Requirements and Natural Gas Rates Application

Response to the Energy Services Association of Canada ("ESAC") Information Request ("IR") No. 2

On May 4, 2011, the FEU filed the Application as referenced above. In accordance with Commission Order No. G-129-11 issuing the amended Regulatory Timetable, the FEU respectfully submit the attached response to ESAC IR No. 2.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Alanna Gillis, Acting Commission Secretary Registered Parties

¹ Comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("Fort Nelson"), FortisBC Energy (Whistler) Inc. ("FEW"), and FortisBC Energy (Vancouver Island) Inc. ("FEVI")



1.0 AES Project Costs

Reference: 2012/2013 RRA: Response to BCUC IR# 201.1 (Page 721)

"The numbers used in the benefit-cost test example results provided in this response are based on the Companies' experience with similar projects in the past."

Reference: 2010/2011 RRA: Response to BCUC IR# 2-12.1 (Page 35)

"TGI's long history of installing gas mains and service lines facilitates the development of standardized costs or the calculation of average installation costs relatively straightforward for the gas system, the work required and the average time to complete and installation. TGI does not have a similar basis for deriving the average cost per installation for alternative energy systems, the work required or the average time required to complete an installation as each project is unique and as such these factors will vary depending upon the installation.

As noted in the response to CEC IR 1.35.6 of the Terasen Utilities ROE application, each alternative energy installation is uniquely configured, and TGI does not have a large number of these installations from which to derive average costs."

Reference: 2010/2011 RRA: Response to BCUC IR# 2-12.2 (Page 36-37)

"Second, the economic assessment approaches are undergoing a very thorough review as part of this Application (the alternative energy solutions section of the Application has already been the subject of dozens of IRs). As such, TGI believes the Commission will be well able to assess and approve the alternative energy service economic models and tariff changes brought forward by the Company. TGI believes that the Commission should review the economic assessment models within this proceeding rather than waiting for a separate proceeding wherein TGI would be providing similar information.

Third, under the proposed approach, the Commission will review contracts entered between TGI and alternative energy customers, providing additional protection for customers."



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1.1 Please confirm that the live spreadsheets provided to the Commission as part of the response to BCUC IR # 201.1 can be supplied to ESAC subject to a confidentiality undertaking.

Response:

As noted in the response to BCUC IR 2.94.4, it is the <u>working electronic</u> nature of the spreadsheets provided in response to BCUC IR 1.201.1 that is proprietary to FEU, and that the Companies wish to maintain as confidential. ESAC membership is comprised of some entities that are competing with FEU thermal energy services area for business and the FEU are not willing to provide working spreadsheets that are used for EEC benefit-cost analysis of programs to competitive entities. The disclosure of the working electronic spreadsheets would result in commercial harm to the FEU to the benefit of competitors.

The content of the various tabs in the spreadsheets are provided in Attachment 1.1 to this response.

1.2 Given that FEI did not have sufficient experience with alternative energy system installations at the time of the 2010/2011 RRA process from which to derive average costs, please indicate the anticipated basis for cost estimates for AES projects that will be used in the economic assessments and resultant tariff applications.

Response:

The question is concerned with thermal energy services rate design, and as such is not relevant in the context of this Revenue Requirements Application concerned with setting natural gas rates.

1.3 Please indicate whether FEI believes its shareholders should absorb the risk of the actual project cost exceeding the cost estimate used in the Economic Test and tariff submission. Does that view change depending on whether FEI obtains a specific CPCN for a particular project? If in any circumstance where FEI's shareholders should not bear this risk, how will that excess cost be recovered and by whom?



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As part of the BCUC Order No. G-141-09, the project costs for all thermal energy projects will collect in the New Energy Solutions Deferral Account or now called the Thermal Energy Service Deferral Account, and will not be recoverable from natural gas customers. Where costs in the deferral account have been prudently incurred, regulatory principle dictates that they are recoverable from thermal energy service customers as a thermal energy service cost of service. This is true regardless of whether the costs are higher than originally forecast, and regardless of whether or not the capital expenditures are subject to a CPCN. The shareholder bears the risk of non-recovery for imprudently incurred costs, as is the normal regulatory principle.

The rate design currently employed to allocate the prudently incurred costs of service among specific thermal energy services customers or projects is to set rates for a particular project that recover at least the forecast costs related to that particular project over the life of the project, together with a contribution to common thermal energy services costs in the deferral account. But if there is a variance from the forecast on a particular project that is not reflected in the rate charged in relation to that project, the FEU believe that the variance should logically be captured in the deferral account and is still a cost eligible for recovery from thermal energy services customers as a whole as part of the overall revenue requirement for that class of service. How and when those costs get recovered, and from which thermal energy services customers, is ultimately a matter of future thermal energy services rate design, and not this revenue requirements application that is concerned with the determination of natural gas rates.

1.4 Please provide representative samples of sales and marketing information provided by FEI to prospective customers outlining the terms and conditions of the agreement, in particular, whether the customer bears any risk in relation to project capital cost, operating cost or project performance and whether the terms and conditions have been reviewed and approved by the Commission.

Response:

The question is concerned with the sales approach for the thermal energy services business, and is not relevant in the context of this Revenue Requirements Application concerned with setting natural gas rates.



2.0 AES Project Costs

Reference: 2012/2013 RRA: Response to CEC IR 4.2 (p. 26)

"III. Thermal Energy Solutions

As discussed in Section 5.3.18.2 of the Application (Exhibit B-1), FEI has allocated a charge, \$0.5 million, from the gas business to Thermal Energy Solutions for recovery of O&M representing the administrative costs of supporting the business in both 2012 and 2013. Furthermore, all direct O&M costs (including project costs) are captured in the Thermal Energy Service Deferral Account, as discussed in Appendix G of this Application. <u>These allocated and direct O&M costs will be recovered from future</u> <u>Thermal Energy Solutions customers</u>. This allocation ensures that no negative impact on natural gas delivery rates will result from the development and delivery of Thermal Energy Solutions. An increase in natural gas throughput as a result of Thermal Energy Solutions has not been forecast in this Application." **{Emphasis added}**

- 2.1 Please advise as to the basis on which:
 - a. future TES customers will contribute to the recovery of "allocated" and "direct O&M costs";

Response:

The costs allocated to thermal energy services will not be recovered from natural gas customers under the current structure approved in the 2010-2011 RRA NSA. The question is concerned with thermal energy services rate design, and as such is not relevant in the context of this Revenue Requirements Application concerned with setting natural gas rates.

b. FEI established the methodology of contribution allocation; and

Response:

As described in the response to ESAC IR 2.2.1c below, the direct costs associated with thermal energy services are directly charged to the thermal energy services class of service. Please see the response to Corix IR 2.3.1 for an explanation of how the FEU arrived at its methodology for allocating indirect costs to the thermal energy services class of service.



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c. how these recoveries will be credited back to natural gas customers.

Response:

As contemplated in the FEI 2010-2011 RRA NSA (BCUC Order No. G-141-09), allocated O&M costs will be credited to the natural gas O&M costs, thereby reducing those O&M costs, and charged to the Thermal Energy Services Deferral Account (formerly the New Energy Solutions Deferral Account). This will generate greater efficiencies in the FEU by absorbing a portion of the overhead and common costs that FEI would not avoid if thermal energy services was not provided and that natural gas customers would otherwise be charged in their rates. The direct costs of thermal energy services projects will be charged directly against the Thermal Energy Services Deferral Account. The costs within the Thermal Energy Services Deferral Account will be recovered through the rates established for the thermal energy projects. Costs in the Thermal Energy Services Deferral Account will not be recovered from natural gas customers.

2.2 Has FEI quantified the amount to be recovered in 2012 and 2013? Is the recovery by natural gas customers limited to the \$0.5 million referred to in the Application?

<u>Response:</u>

As indicated above, FEI will charge to the Thermal Energy Solutions Deferral Account the actual direct costs (project costs and O&M), plus the \$0.5 million allocation of overhead costs from the gas class of service for each of 2012 and 2013 for recovery from customers of the thermal energy class of services.

The \$0.5 million allocation of overhead costs directly reduces natural gas rates by that amount in each of 2012 and 2013, whereas, the direct costs (project costs and O&M) will not affect the rates for natural gas customers since FEI will charge them directly to the Thermal Energy Solutions Deferral Account.

The \$0.5 million annual allocations are reasonable at this time for the reasons described in FEU response to BCUC IR 1.78.1 and are fixed amounts for rate setting purposes in each of 2012 and 2013.



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2.3 To what extent, if any, is the amount of future recoveries beyond 2013 dependant on the number or the success of the FEI TES projects?

Response:

With respect to the allocation of administrative costs to the thermal energy class of service beyond 2013, that amount will be determined considering the activity level of the thermal energy class of services at that time. Given that the market is at an early stage of development and as the projects can vary in terms of their size and timing it is difficult to assess what future level of administrative support will be required at this time. Although the FEU will be adapting the overall level of activity according to our evolving assessment of the prospects of success in the thermal energy services development, the amount of future recoveries of the associated costs will not be directly tied to the number of successful projects because recoveries should be based on the amount of prudent activity regardless of whether particular projects succeed.

2.4 Do all TES Deferral Account balances earn AFUDC? How many years will projects be kept in the TES Deferral Account before they are deemed to be successful or unsuccessful?

Response:

This question is not relevant to the present proceeding since the deferral account in question does not affect natural gas revenue requirements or rates.

2.5 Of the \$12.95 million of projected direct costs for Thermal Energy projects in development in 2010 and 2011 that were provided in Table G-2 of the 2012/2013 RRA (Appendix G, Page-4), please indicate if any of this projected amount is potentially associated with projects that may not be successful or ultimately approved by the BCUC.



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Direct costs are incurred to advance projects that the FEU believe are viable. It is always possible that, in the future, one or more candidate projects may not proceed. But it is too soon to tell at this stage. FEI's thermal energy class of service is in an early stage of development and as such each project will require time to develop to ultimately determine its level of success. All thermal energy projects submitted to the BCUC will follow the requirements outlined in BCUC Order No. G-141-09. Prudently incurred costs recorded in the deferral account should ultimately be recoverable from thermal energy customers, as is the normal principle with public utility regulation.

- 2.6 What will ultimately happen with the accumulated costs associated with unsuccessful projects, including their direct costs, and their pro-rated portion of Sales & Marketing, Overhead and AFUDC? Who among the following will absorb these costs:
 - a. natural gas customer;
 - b. other TES customers; or
 - c. FEI shareholder?

Response:

The assumption of risk for non-recovery of amounts in the Thermal Energy Service Deferral Account (formerly referred to as the New Energy Solutions Deferral Account) was outlined in BCUC Order G-141-09. It states that the risk of non-recovery will not be borne by natural gas ratepayers and will not be recovered through natural gas rates. Whether or not a project proceeds, all costs related to the thermal energy services class of service within the utility including direct costs, sales and marketing O&M and business development costs, and the overhead allocation from FEI will accumulate within the Thermal Energy Service Deferral Account and will be recovered through the rates charged to thermal energy service customers established for the thermal energy projects. Thus, under the current regulatory framework, the ultimate risk of non-recovery of amounts accumulated in the Thermal Energy Service Deferral Account is with the shareholder.



3.0 Confidential Customer Information

Reference: 2012/2013 RRA Response to BCUC IR 157.1 (p. 564)

"The FEU are submitting this response on a confidential basis under separate cover as the response reveals confidential customer information related to projects currently under negotiations and would adversely affect commercial negotiations if disclosed."

3.1 Please confirm for each project listed that written approval was obtained from each customer before the release or use of the customer's billing information or other confidential information to or by employees in the thermal energy services group developing these projects. Please provide copies of those written approvals, if any.

Response:

This response also addresses the responses to ESAC IRs 2.3.2 and 2.3.3.

Historical natural gas billing data is general information of limited value when developing a thermal energy system. First, historical information does not exist for new construction. Second, the historical natural gas billing data includes the total gas consumption at the meter which may or may not be the natural gas consumption needed only for the production of the thermal energy that will be replaced by the thermal energy service. A customer's gas usage may include consumption for activities unrelated to the requirements of a thermal alternative energy system, such as for example, cooking in restaurants or institutions, or commercial process load. Third, natural gas may not be the only energy source used by a customer in the generation of thermal energy so historical natural gas consumption may be only part of the picture. Consequently, it is not possible to understand whether historical natural gas billing data equals the natural gas consumption that is necessary for thermal energy production or whether energy sources are involved, without an evaluation of the specific equipment and usage requirements of the customer at the site over time. Fourth, the type, nature, and location of the heating and cooling equipment systems in buildings may or may not be compatible with thermal energy solutions. Therefore, the FEI database of historical natural gas billing data alone is not an effective tool for identification of marketing opportunities for thermal energy service in the absence of the accompanying technical evaluation by site. As such, natural gas consumption history is not used by FEI to market thermal energy systems.

Evaluation of a thermal energy project usually requires a feasibility analysis that specialists perform. These experts may request and review historical natural gas billing information in the process of performing their technical evaluation.



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In the event that FEI is not the thermal energy service provider, but is the natural gas service provider, a simple request by the customer to FEI to share the historical natural gas billing data at their site with the proponent to assist in their technical evaluation is all that is required. Alternatively, many customers keep records of their consumption data and may actually provide the information to the proponent on their own, without the assistance of FEI.

In the event that FEI is the thermal energy service provider and the natural gas service provider, no formal request is necessary on behalf of the customer for FEI personnel to utilize the historical billing data in the evaluation of the project. This is because the thermal energy service is simply another class of service within the public utility, not a separate entity. Nonetheless, since this type of information would only be useful in conjunction with the technical evaluation of the project, customers expect FEI to review their historical billing data at that stage. For expediency, many customers actually provide this information to FEI since they often have it readily at hand.

At all times, FEI maintains conformance with the Personal Information Protection Act.

3.2 Please confirm that (i) customer natural gas usage history data is held confidential by FEI and, other than as may be contained in an aggregation of data to which no individual customer can be identified, is not used for any purpose other than billing the customer or managing a customer's account internally at FEI, (ii) all non-FEI personnel and TES project developers are required to have, and actually have, natural gas customer's written permission prior to having access to or use of customer natural gas usage history information.

Response:

Please refer to the response to ESAC IR 2.3.1.

3.3 Please confirm that at no time has FEI, directly or indirectly, used the natural gas consumption history data of a customer to market an alternative energy system on behalf of FEI or any affiliate.

Response:

Please refer to the response to ESAC IR 2.3.1.



4.0 Thermal Energy Services for Schools

Reference: 2012/2013 RRA Appendix K Section 4.3 Page 14

"FortisBC is proposing a \$22 million incentive program for geoexchange and energy efficiency retrofits in up to 260 schools over two years"

Reference: 2012/2013 RRA - Response to BCUC IR 204.3 & 204.3.1

4.1 Please indicate if, prior to the submission of the 2012/2013 RRA, any FEI staff members, including any member of the designated Thermal Energy Services Group, discussed with any School Districts the possibility of TES EEC funding being approved under the pending RRA. If so, please indicate if any of these discussions took place in the context of FEI or any affiliate developing Thermal Energy solutions for these customers whereby the EEC funding would potentially be used the improve the financial viability of TES projects that would be owned and operated by FEI. Please indicate the number of School Districts (including the total number of schools involved) where these discussions have taken place.

Response:

The FEU are assuming that the "TES" referred to in this question refers to the Companies' proposed Thermal Energy for Schools Program, for which approval has been requested in this Application (Exhibit B-1), and the response to this question is based upon that assumption.

Staff involved in discussions with School Districts do not specifically recall such discussions taking place, but it is generally the case with all of our customers that they are interested in and inquire about available incentives from all sources (whether the utility or government). The FEU sales staff recognize that they are not in a position to make any commitments about EEC funding. Each customer must qualify for EEC funding based on the terms and conditions of the EEC program to which the customer is applying. Moreover, as the proposed Thermal Energy for Schools Program has not yet been approved, the Companies' EEC team has not yet commenced program design for Thermal Energy for Schools, which would include the development of the terms and conditions for a Thermal Energy for Schools Program.

4.2 Please indicate if any of FEI's TES staff is permitted to discuss potential EEC funding that may be available for customers on FEI TES projects or if only designated EEC staff, as part of the regulated natural gas utility, are permitted to have these conversations with customers.



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There are no rules that would preclude thermal energy services staff from discussing EEC funding that may be available for customers on FEI thermal energy services projects. However, as described in the responses to Corix IRs 2.4.6 and 2.5.13, there are different groups of employees that are typically involved in EEC and thermal energy services projects. In any case, EEC funds are provided to customers, not FEI. Competitors of FEI for thermal energy service are also free to discuss any EEC funding that may be available to their customers as well.

4.3 If discussions have taken place with School Districts about the possibility of using EEC funds for FEI Thermal Energy projects, please advise how the levels of EEC funding for each project were arrived at and whether or not these amounts were predicated on the approval of the Societal Test methodology that is part of this RRA.

Response:

Please refer to the response to ESAC IR 2.4.2 regarding the communication of EEC programs.

To date only the Delta School Board has applied for an EEC incentive related to an FEI thermal energy project. The Delta School District's application came through the PSECA program, details of which can be found on pages 74 to 77 of the 2010 EEC Annual Report, filed as Appendix K-4 to Exhibit B-1. The FEU have also corresponded with the Central Okanagan School District specific to one school about the provision of an EEC incentive under the Commercial Custom Design program, which program is detailed on pages 86 – 89 of the 2010 Annual Report, filed as Appendix K-4 to Exhibit B-1 and the FEU expect the School District to apply for the incentive. As the Societal Test methodology is part of the current RRA it has not been used for any calculations other than those included in this and earlier rounds of Information Requests. The proposed Thermal Energy for Schools Program is a new program proposed within this RRA and unless the Societal Test or elements thereof are approved, the proposed Thermal Energy for School District's EEC PSECA incentive application was undertaken using the TRC, as that is the benefit-cost test currently approved for use by the FEU's EEC team.

For an explanation of how the PSECA incentive for the Delta School District was calculated, please refer to the response to ESAC IR 2.6.5.



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4.4 Please advise if FEI has negotiated any Thermal Energy agreements, whether or not in final form, with any School Districts that are contingent on the approval of the TES EEC funding in the 2012/2013 RRA and/or the approval of an associated Thermal Tariff by the BCUC. If so, please indicate the number of schools that would be involved in these projects.

Response:

FEI has not negotiated any thermal energy agreements with any School Districts that are contingent on the approval of the Thermal Energy for Schools EEC funding in the 2012-2013 RRA or the approval of an associated Thermal Tariff by the BCUC.

4.5 Please advise how other firms wishing to develop TES projects with School Districts would have become aware of the potential existence of EEC funds being requested for School District TES projects in the 2012/2013 RRA? Please indicate if this was marketed to other firms and, if so, please provide any relevant promotional material or letters to corroborate.

Response:

Since the EEC funds being requested in this 2012-2013 RRA proceeding for Thermal Energy for Schools Program have not yet been approved by the Commission, program design for a Thermal Energy for Schools Program has not yet commenced and there is no program for Thermal Energy for Schools as yet. Therefore, there is nothing to be communicated to School Districts and other market actors. It is the Companies' practice, that once a program is developed, such as the Efficient Boiler Program (in which BC Housing, who is a customer of a member of ESAC, participated) various communications channels are used to make program details available:

- Information about all programs, with all terms and conditions, is placed upon the Companies' website;
- Program collateral, including information brochures, is produced and made available to customers and others through the FEU website;



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- The FEU staff provide program briefings to industry groups through inclusion of material in industry group newsletters and presentations to meetings of industry groups; and
- The FEU staff participate in such trade shows as the School Plant Officials' Association, Buildex, Union of British Columbia Municipalities etc. at which program information is shared.

Should the Commission approve the funding requested in this proceeding for Thermal Energy for Schools, a program will be developed. The program details will be shared through the mechanisms noted above as well as with the Companies' EEC Stakeholder Group and in the EEC Annual Report. The EEC Report is filed with the Commission by March 31 of each year. While the Companies make every effort to "push" information about programs into the public domain, it is the view of the FEU that market actors such as customers and suppliers also have some responsibility to access the information that is publicly available and inform themselves about programs that might benefit them or their customers.



5.0 Boiler Replacements – EEC Funding

Reference : 2012/2013 RRA (Appendix G Section 2.4 Page 12 Table G-1)

"FEI has an agreement with the Delta School District for the delivery of cleaner thermal energy for 17 schools and two school district buildings through the implementation of state-of-the-art geoexchange systems and <u>high-efficiency condensing boiler</u>s, which will replace aging heating plants at school district sites. These systems provide many benefits, ranging from saving energy and improving indoor comfort to stable energy rates and a smaller carbon footprint." (emphasis added)

Reference: 2012/2013 RRA Response to BCUC IR #189.2 (page 654)

"Thermal Energy for Schools provides incentives for the installation of ground source heat pumps."

Reference: 2012/2013 RRA Response to BCUC IR #204.1.1 (page 742)

"The Thermal Energy for schools program is anticipated to provide incentives for state-of-the-art low carbon energy systems such as geoexchange systems and <u>high-efficiency boiler upgrades</u>." (emphasis added)

Reference: 2010/2011 RRA (Part III, Section-C Tab-3, Page 261)

"For the purpose of this application, integrated and alternative energies include geo-exchange, solar thermal and District Energy systems."

Reference: 2010/2011 RRA (Part III, Section-C Tab-3, Page 263)

"District energy systems ("DES") employ a range of energy technologies and sources to deliver piped heating (hot water) and/or cooling (ambient or chilled water) to <u>multiple buildings and customers within a</u> <u>neighbourhood</u> from a central plant location or locations" (emphasis added)

5.1 Given that the IR responses on pages 654 and 742 dealing with TES EEC funding conflict with each other, please indicate if the EEC funding requested for the Thermal Energy for Schools (TES) program is intended to cover high efficiency boiler replacements. If yes, please explain how this funding is different from the existing High Efficiency Boiler EEC program.



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As a point of clarification, the FEU have been using TES as an acronym for "thermal energy systems" being offered under GT&C Section 12A "Alternative Energy Extensions", and thus it might lead to confusion to also use "TES" as an acronym for Thermal Energy for Schools Program.

The FEU disagree that the responses to BCUC IRs 1.189.2 and 1.204.1.1 conflict with each other. The proposed Thermal Energy for Schools Program will involve the provision of EEC funding for new thermal energy systems for schools in BC. Neither of the two IR responses lists all the possible energy solutions that might possibly be involved in this program. For instance thermal energy could be provided partly by solar thermal systems or efficiencies may be achieved through the implementation of advanced control systems.

The approval of \$22 million in EEC funding is requested for an EEC program supporting Thermal Energy for Schools, to which any customer might apply if approval is granted and once a program has been designed and implemented. The \$22 million of EEC funding requested for Thermal Energy for Schools does not have a specific breakdown of amounts anticipated to be allocated to boilers versus other technologies. Thus, the Thermal Energy for Schools Program could, but would not necessarily, include boiler upgrades.

The Thermal Energy for Schools Program is also different from the existing High Efficiency Boiler EEC Program in that for the existing Efficient Boiler Program, the applicant submits a request for a boiler replacement based on the requirements of one individual building. In the proposed Thermal Energy for Schools Program the equipment replacements for several schools in the school district are reviewed as a single application to the proposed Thermal Energy for Schools Program and the replacements can be comprised of boilers or other equipment such as geoexchange systems.

School districts operate in a challenging environment where they must reduce greenhouse gas emissions without increasing operating costs and in the absence of access to sufficient capital to employ lower emission technologies. It is the objective of the proposed Thermal Energy for Schools Program to enable school districts to conserve energy and improve energy efficiency in their buildings, while also reducing greenhouse gas emissions in a cost effective manner, using the best fitting technology solution by site, and to achieve these benefits within existing operating budgets and capital constraints for the entire school district. The technology options might include geoexchange, high efficiency natural gas boilers and/or other technologies such as enhanced controls.



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5.2 Given that the above definitions of AES services in the 2010/2011 RRA and subsequent NSA do not include boiler replacements, please indicate whether and where FEI has received prior approval to include these types of retrofits as part of the proposed regulated AES offerings.

<u>Response</u>

This question relates to rate design for the thermal energy services class of service, and is not relevant to the present proceeding that is concerned with setting natural gas rates.

5.3 Please advise whether or not the thermal energy supplied by these boilers is measured for tariff purposes and whether or not the customer continues to pay the gas bill for the meter upstream of the boilers.

Response:

For the Delta Schools project the thermal energy will be measured and the customer will not continue to pay the gas bill for the meter upstream of the boiler.

5.4 If the customer continues to pay the gas bill for the upstream meter, please provide a rationale for why the installation of boiler replacements and their repayment over time should be considered a regulated service as opposed to a non-regulated financing mechanism.

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

5.5 If the customer continues to pay the gas bill for the upstream meter, please indicate why this service should not be covered under the RMDM guidelines.



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This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

5.6 If the customer continues to pay the gas bill for the upstream meter, please indicate if FEI is providing any efficiency performance guarantees for the new plants based on the thermal energy generated per unit of gas consumption.

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

5.7 Please indicate if FEI has been developing AES/TES projects with other school districts that include boiler replacements as part of the proposed regulated services. If so, are EEC funds included in those projects?

Response:

FEI is developing thermal energy projects with other schools districts and boiler replacements are expected to comprise a portion of the new thermal energy systems installed in these projects.

FEI expects that the customers proposing these projects will be eligible for EEC funding; however, since aspects of EEC funding are subject to the approvals being sought in this Application (such as, for example, the request to adopt the SCT as the evaluation basis for EEC programs) the final nature of the EEC evaluation framework is uncertain at this time. Also, detailed program design for Thermal Energy Service for Schools Program will only occur after Commission approval has been granted. Regardless of how the final approvals affect the Thermal Energy for Schools Program, the EEC funding will be equally available to all customers (i.e. schools and school boards, in this case) that meet the specifications of the program whether the energy systems are owned by the schools or are owned by FEI or another utility provider.



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5.8 What is the estimated amount of the \$22 million of EEC funding for Thermal Energy for Schools that will be used for boiler replacements?

Response:

Please also refer to the response to ESAC IR 2.5.1. The \$22 million of EEC funding requested for Thermal Energy for Schools does not have a specific breakdown of estimates between the amounts anticipated to be allocated to boilers versus other technologies. Approval has not been granted for funding for this Program Area, thus program design for this initiative has not yet begun or been fully developed.

5.9 Please indicate the relationship between the FEI staff that are developing these projects with school district customers and the FEI staff responsible for approving and distributing EEC funds under the High Efficiency Boiler program.

Response:

The staff involved in developing projects for school district customers are distinct from those that distribute EEC funds under the High Efficiency Boiler program.

The FEU staff that develop the thermal energy solution projects are in the Thermal Energy Solutions group, reporting to the Director, Business Development. The FEU staff responsible for administering the Efficient Boiler Program are in the EEC group, and in the Energy Products and Services group, reporting to the Director, Resource Planning and Market Development. Once an application for participation in the Efficient Boiler Program is received from a customer, it is reviewed by the Energy Products and Services Group. Then the application is forwarded to the EEC group, which ensures that all terms and conditions for the program are met, including that qualifying equipment has been installed, and issues the rebate cheque to the customer based on the program funding formula. All program details for all programs are available on the FEU's website, www.fortisbc.com. The Thermal Energy Solutions group staff that might be involved in developing the actual thermal energy projects with a customer choose to work with the FEU, are not involved in the process of designing EEC programs including applications to EEC programs.



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5.10 Please provide any examples FEI is aware of outside of B.C. in which the ownership of replacement boilers is held in a regulated utility and the costs are recovered in a regulated rate tariff approved by a regulatory commission.

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.



6.0 Delta School District Project

Reference: 2012/2013 RRA Response to BCUC IR #213.4 (page 792)

"Also under the PSECA program, FEI is working with Delta School District to put together a thermal energy services package for this customer. EEC incentives will likely form part of this package; however the incentive amount has not yet been finalized so is not included in this table".

Reference: 2012/2013 RRA Response to BCUC IR #1.2 (page 2)

"As explained on page 15 of the Application (Exh B-1-2), FEI is expecting to bring forth individual projects with signed contracts for Commission approval later this year.

As AES Projects develop further, FEI may consider applying to the Commission for approval of AES projects on a different basis"

Reference: Press Release Data Feb 7th 2011

Thermal Energy Upgrade [see Appendix A to this ESAC IR No. 2]



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The Thermal Energy Upgrade Project is a unique partnership between the Delta School District and Terasen Gas Inc. (TGI) whereby TGI will undertake the work to The internal thergy opgrate project is a unique partnership between the between the busic tails in tersen tails interact (for) whereby for mains and the and the work replace and convert the heating/cooling plants of the remaining 19 sites in the District inventory not yet upgraded, assume ownership of the plants when completed, operate and maintain the plants, and then charge a tariff to the District for "thermal energy" consumed much in the same fashion Terasen charges consumers for natural gas consumption and BC Hydro charges for electricity consumption. The project also includes the work necessary to alter and connect existing mechanical systems at those buildings to accept the new technology.

This approach to purchasing thermal energy pools the costs and benefits of each building in a manner that enables the District to maximize the environmental benefits of employing alternative technologies in a timely manner (two-year implementation period) while managing capital and operating costs within existing, tight constraints.

Technologies Used

1. Open Loop Geothermal System (OLS)

An open loop system uses groundwater from a water well tapped into the aquifer 100m or deeper below ground level as a heat source. The groundwater is pumped into the indoor ground water heat pump unit where heat is extracted and the water is disposed of by way of a return well back to the aquifer. Because groundwater is a relatively constant temperature year-round, wells are an excellent heat source. Testing for this technology was conducted in the neighbourhoods where all 19 buildings are located, and of those, eight schools were deemed to be physically and financially feasible.

2. Closed Loop Geothermal System (CLS)

A closed loop system uses a continuous loop of buried polyethylene pipe. The pipe is connected to the indoor ground source heat pump to form a sealed, underground loop through which an environmentally friendly antifreeze-and-water solution is circulated. A closed loop system constantly re-circulates its heat-transferring solution in pressurized pipe, unlike an open loop system that consumes water from a well. Most closed loops are trenched horizontally in areas adjacent to the building and where adequate land is not available, loops are vertically bored. Typically, the cost of the closed loop system, hunch higher than that for an open loop system. Those sites which didn't pass the feasibility test for the open loop system were then evaluated for the closed loop system, and from these only three sites were deemed feasible,

3. Condensing Boiler Upgrade (CBU)

In a conventional boiler, fuel is burned and the hot gases produced are passed through a heat exchanger where much of their heat is transferred to water, thus raising the water's temperature. One of the hot gases produced in the combustion process is steam, which is for all intents and purposes wasted. A condensing boiler extracts additional heat from the waste gases by condensing the steam into liquid water, thus recovering its latent heat. A typical increase of efficiency can be as much as 10-12%. This is the least expensive of all of the alternative thermal energy systems considered in this project, and also yields the least amount of energy and carbon emission reduction. The last eight buildings out of the 19 considered in this project will receive this form of retrofit.

Pertinent Project Data

1. Buildings Included:

- Delta Secondary (OLS)
- School Board Office (CLS) Annieville Elementary (CBU)
- Delview Secondary (OLS) Beach Grove Elementary (CBU) .
- English Bluff Elementary (OLS) Chalmers Elementary (CBU)

(CBU)

- North Delta Secondary (OL5) Pinewood Elementary (OLS) · Cliff Drive Elementary (CBU)
- Richardson Elementary (OLS) Heath Elementary (CBU)
- South Delta Secondary (OLS) - Holly Elementary (CBU)
- South Park Elementary (OLS)
- Ladner Elementary (CBU) - Delta Manor Education Centre - District Maintenance Facility
- (CLS) - Neilson Grove Elementary (CLS)
- 2. Project budget: \$4.9 Million
- 3. Funding sources: Energy Efficiency & Conservation (EEC) Program (\$800,000), Terasen Gas Inc. (\$2.7 Million), Public Sector Energy Conservation Agreement (PSECA) Program (\$1.4 Million)
- 4. Project Duration: 2 years, starting in Summer 2011

5. Estimated Annual Reductions:

Total energy: 32,000 gigajoules

2,000 tonnes of carbon dioxide (tCO2e) Emissions: Utility costs*: \$100,000 Avoided carbon tax and offsets: \$50,000

- takes into account new TGI thermal energy tarifi



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NEWS RELEASE

For Immediate Release 2011ENV0007-000102 Feb. 7, 2011 Ministry of Environment Terasen Gas

SCHOOL DISTRICTS WARM TO RENEWABLE ENERGY TECHNOLOGY

VICTORIA – B.C. school districts have an interest in saving money and being conscientious about energy use – and the Delta School District is among those leading the charge by tapping into B.C.'s Public Sector Energy Conservation Agreement fund.

Terasen Gas and the B.C. Government are providing \$6.9 million for 35 energy projects in ten school districts to help reduce greenhouse gas emissions, energy consumption and costs.

"By working together, we're able to realize significant savings opportunities," said John Yap, Minister of State for Climate Action. "It starts with thinking about how we use and conserve energy and then implementing renewable technologies such as geothermal exchange and solar thermal air technologies."

The projects range from energy infrastructure upgrades to solar wall installations to state-of-theart geoexchange systems buried beneath11 Delta School District playing fields to capture the heating and cooling properties of the earth.

"Energy conservation and environmental responsibility are fundamental values for Terasen Gas. We are committed to developing innovative energy solutions to help meet the current and future energy needs of B.C. school districts," said Doug Stout, vice president, Energy Solutions and External Relations at Terasen Gas and FortisBC. "Our collaboration with the Delta School District is an excellent example of what can happen when many parties come together to find creative uses of integrated energy solutions. Through projects such as these, we can inspire students across B.C. to be conscientious about the energy they use."

"We are extremely pleased to see our project come to life," said Dale Saip, board chairperson, Delta School District. "The teamwork and shared vision of our organizations has resulted in an incredible learning opportunity for our kids and our community. We are grateful to Terasen and the Province of B.C. for their commitment to a better future in Delta and school districts throughout the province."

The combined annual energy savings from the 35 projects are estimated at nearly \$720,000 and annual greenhouse gas (GHG) reductions of almost 2,800 tonnes, which is the same as removing over 600 cars from the road annually.



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"The teachable moments being created are an invaluable side benefit," said Minister of Education Margaret MacDiarmid. "The energy projects and the discussions I know many teachers are having in their classrooms are piquing student curiosity and sending a great message about the choices we can make for the environment and our future."

The Public Sector Energy Conservation Agreement is a provincial partnership with Terasen Gas, BC Hydro, SolarBC, and Natural Resources Canada. Partners provide capital funding and/or technical support for public sector energy proposals. Another \$12 million in capital funding will be distributed later this year.

To date, the fund has helped achieve annual energy cost savings of more than \$7.4 million and GHG reductions of over 18,700 tonnes.

About Terasen Gas

Terasen Gas is composed of the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. Terasen Gas is a leading integrated energy solutions provider, focused on the safe and reliable provision of natural gas, propane and alternative energy solutions. Terasen Gas serves approximately 939,000 residential and commercial customers in more than 125 B.C. communities. Terasen Gas employs more than 1,280 people in British Columbia and is indirectly wholly owned by Fortis Inc., the largest investor-owned distribution utility in Canada. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS. Additional information can be accessed at www.fortisinc.com or www.sedar.com.

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("IR") No. 2

Appendix A - ESAC IR#2

BACKGROUNDER

DELTA SCHOOL DISTRICT PROJECTS

- Terasen Gas will be working with the Delta School District to replace eight conventional boilers with high efficiency, condensing boilers and install 11 state-of-the-art geoexchange systems.
- · Terasen Gas estimates that the total environmental benefit of the Delta School District project would be an approximate:
 - o 55 per cent reduction in energy consumption (equivalent to enough natural gas to heat about 365 homes for one year)
 - 69 per cent reduction in greenhouse gases (equivalent to the removal of almost 450 cars from the road annually)
- Terasen Gas would own, operate and maintain all of the new heat generation equipment and would charge the Delta School District a rate approved by the British Columbia Utilities Commission for the energy's delivery.
- All 19 projects would be completed in less than two years, and could eventually be expanded to take on other buildings which have already received thermal energy retrofits.
- As a leading integrated energy provider, Terasen Gas builds and operates geoexchange systems for multi-residential, commercial, and industrial developments.
 - o Geoexchange systems are one of our principal integrated energy solutions and can be implemented in both new construction and retrofits.
 - o Extracting energy from the earth provides a renewable source of heating and cooling.
 - Geoexchange systems provide many benefits for the public sector, developers, building owners and end users ranging from indoor comfort, to protecting the environment, to stable rates that provide a level of financial certainty regarding the price of energy.

GEOEXCHANGE PROJECTS in School District #37 (Delta):

- Delta Secondary
- · Delview Secondary
- English Bluff Elementary
- Neilson Grove Elementary
- North Delta Secondary
- Pinewood Elementary
- Richardson Elementary
- South Delta Secondary
- South Park Elementary
- Board of Education Office
- Delta Manor Education Centre



HIGH EFFICIENCY BOILER UPGRADES in School District #37:

- Annieville Elementary
- Beach Grove Elementary
- · Chalmers Elementary
- Cliff Drive Elementary
- · Heath Elementary
- Holly Elementary
- · Ladner Elementary
- · District Operations Centre

SOLAR AIR PROJECTS:

- J.A. Laird Elementary, School District #6 (Rocky Mountain)
- Williams Lake Secondary School, School District #27 (Cariboo-Chilcotin)
- Queen Elizabeth Secondary School District #36 (Surrey)
- Semiahmoo Secondary, School District #36 (Surrey)
- Fleetwood Park Secondary, School District #36 (Surrey)
- Elgin Park Secondary, School District #36 (Surrey)
- Smithers Secondary, School District #54 (Bulkley Valley)
- Walnut Park Elementary, School District #54 (Bulkley Valley)
- Agassiz Elementary-Secondary, School District #78 (Fraser-Cascade)

ENERGY UPGRADES:

- Edgewater Elementary, School District #6 (Rocky Mountain)
- Tatla Lake Elementary-Secondary, School District #27 (Cariboo-Chilcotin)
- Kelly Creek Community School, School District #47 (Powell River)
- Keating Elementary School, School District #63 (Saanich)
- Sidney Elementary School, School District #63 (Saanich)
- Arden Elementary, School District #71 (Comox Valley)
- Timberline Secondary School, School District #72 (Campbell River)

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Contact:	Colin Grewar,	Marcus Wong
	Ministry of Environment	Corporate Communications Manager
	250 387-9630	Terasen Gas
		Phone: 778 571-3263
		Email: marcus.wong@terasengas.com
		Follow us at: www.twitter.com/terasengas

For more information on government services or to subscribe to the Province's news feeds using RSS, visit the Province's website at <u>www.gov.bc.ca</u>.



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6.1 The information on FEI's website indicates that the project will result in a net annual utility savings of \$100,000 per year for the Delta School District ("DSD") after accounting for the cost of the new thermal tariff. Will the tariff negotiated for this particular project be based on this financial outcome for the DSD or will the tariff be based on what is required to fully recover all of FEI's applicable costs within the term of the agreement?

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

6.2 Please advise whether (i) the total capital cost of \$4.9 million for the project is a fixed "all in" cost, and (ii) the \$4.9 million figure was in any way influenced by the \$5.0 million threshold for a CPCN hearing that formed part of the 2010/2011 RRA Negotiated Settlement Agreement. Also please indicate whether or not, in FEI's opinion, a CPCN would be required if it came to the attention of FEI that the total capital cost would exceed the CPCN threshold after the Tariff had been approved by the Commission.

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

6.3 Which party is assuming the risk as to whether the net estimated utility cost savings will be realized? Which party is assuming the risk if the total project costs are exceeded?

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

6.4 Was the marginal rate for BC Hydro Large General Service electricity rates (i.e. LGS – Part 2 approved and effective January 1st, 2011) factored into the



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estimated impact on electricity costs for the DSD? Were forecast future increases in this rate factored into the analysis?

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

6.5 How was the EEC funding for this project calculated? Specifically, how much of the publicly announced \$800,000 was from published incentive programs such as the Efficient Boiler Program and how much was based on project-specific or customized incentives?

Response:

The amount of EEC funding available to the Delta School District (DSD) via their application through the Public Sector Energy Conservation Agreement ("PSECA") is not yet final. The amounts that DSD references on their web site, including the reference to \$800k of EEC funding, are initial estimates only. As such, the final amount of EEC funding will be determined by FEI and released to the School District upon commissioning and on-site audits of the systems. Current analysis of the project application indicates that approximately \$100k of EEC funds will be available to DSD due entirely to the use of high efficiency boiler upgrades at some of the sites.

Any EEC funds that FEI provides to DSD for the thermal plant upgrades will be available through FEU's participation in the PSECA initiative, detailed on pages 74 to 77 of Appendix K-4 to Exhibit B-1. On June 8, 2010, FEI (then Terasen Gas) became a signatory to PSECA, an initiative of the provincial government aimed at reducing energy use and greenhouse gas emissions in public sector buildings. The Companies subsequently developed the PSECA Initiative, to pool investment from the various programs of members including EEC funding, and to streamline the qualification process for projects. Including the DSD, the PSECA initiative provided funding commitments to 10 different organizations for energy efficiency upgrades at 35 separate locations.

The EEC funding becomes available for PSECA applicants such as DSD in the following manner: DSD first submitted an application and detailed energy study to the Climate Action Secretariat ("CAS") for internal CAS review and prioritization. The CAS then forwarded the energy study to the utility PSECA partners (FEI and BC Hydro). FEI reviewed the study to ensure reasonableness of the conclusions, and subsequently submitted each of the proposed



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energy conserving measures (i.e. the proposed thermal upgrade at each school) to the PSECA Initiative's screening and funding models. Each proposed upgrade was first subjected to a Total Resource Cost (TRC) screening. A portfolio of projects which maintain a TRC score of approximately 1.0 was then selected and incentives for each project developed. Incentives were determined based on the expected stream of natural gas savings. More specifically the incentives were calculated as 5 \$/GJ, on the discounted stream of the expected natural gas savings, over 50% of the measure life, up to a maximum of 10 years. This funding model also underlies the upcoming Commercial Custom Design Program, detailed on pages 86 – 89 of Appendix K-4 to Exhibit B-1, and is conceptually similar to other such dollars / GJ saved incentive programs found throughout the country.

6.6 Were the same FEI staff members involved in developing the EAS project with the DSD and determining the EEC incentive amounts?

Response:

No they were not. The project was developed by the Thermal Energy Solutions group within FEI. The Thermal Energy Solutions group at FEI has been working with the DSD for several months to develop a business model and offering that would meet the goals of the customer. Concurrent to this process, the DSD submitted an application for Public Sector Energy Conservation Agreement (PSECA) Initiative for funding for this project. As with all grants or incentives made available in the form of DSM or EEC programs, the customer has a role to play in accessing the programs and meeting the requirements of such programs to qualify for these funds, before the funds can be dispensed.

The PSECA incentive amounts for this project are determined based upon the program parameters, designed and managed by staff on the EEC Team, and described on pages 74 to 77 of Appendix K-4 to Exhibit B-1.

6.7 How much, if any, of the EEC funding for this project was expected to come from the \$22 million of school TES EEC funding included in the 2012/2013 RRA?



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None. EEC incentives for the Delta School District will come from funds approved in the 2010-2011 Revenue Requirements proceeding, under the FEU's PSECA initiative as described on pages 74-77 of Appendix K-4 to Exhibit B-1.

6.8 Is the DSD project one that FEI intends to bring to the Commission for "approval later this year" or is to be brought forward to the Commission "on a different basis"? What is meant by "a different basis"?

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

6.9 If the Commission does not approve a tariff application for this project, please indicate if FEI will still proceed with the project based on the agreed-upon tariff and, if so, whether or not FEI's shareholders will then assume the risks associated with possible non-recovery of actual costs (including capital costs).

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

6.10 Please describe how the benefits of having a regulated tariff for this project were explained to the DSD. In particular, what did FEI tell the DSD would happen (if anything) to its particular tariff or to the rates of other FEI rate payers if the negotiated tariff is insufficient to fully recover all of FEI's applicable costs within the term of the agreement?

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.



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6.11 Has FEI secured firm pricing from third parties for the \$4.9 Million capital cost?

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

- 6.12 Assuming the tariff for this project was approved by the Commission, please indicate what would happen if the actual capital and operating costs of the project exceeded what was embedded in the tariff? In particular, please advise which of the following parties would be at risk for these additional costs:
 - a. the DSD, whether through an increase only in their specific tariff or otherwise,
 - b. FEI's other AES rate payers collectively,
 - c. FEI's natural gas rate payers, or
 - d. FEI shareholders.

Response:

The FEU's response to ESAC IR 2.2.6 addresses the fact that natural gas customers are protected under the current regulatory constructs, and that the ultimate risk of non-recovery of amounts accumulated in the Thermal Energy Services Deferral Account is with the shareholder. The other aspects of this question concern thermal energy services rate design matters and are not relevant to the present proceeding, which is concerned with setting natural gas rates.



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7.0 Delta School District Project Economics

ESAC has reviewed the publicly available information from the sources it was able to find including the press release information from the FortisBC's website, the Delta School Board website and media reports related to the press release. The following is a summary and analysis prepared based on this information:

Publicly Released Information:

Total Net Energy Savings:	32,000 GJ
Total Emissions Reduction:	2,000 Tonnes
Avoided Annual Emissions Offset Costs:	\$50,000 (@ \$25/Tonne)
Total Capital Cost:	\$4.9 Million
PSECA Contribution	\$1.4 Million
EEC Funding	\$0.8 Million
Net FEI Capital Investment:	\$2.7 Million
Net annual savings to the School District:	\$100,000

Assumed CO2e emissions factors:	
Natural Gas:	.050 Tonnes per GJ
Electricity	.026 Tonnes per MWh

Resultant calculation of annual utility reductions:		
Natural Gas:	41,352 GJ	
Electricity	-2,599,832 kWh (i.e. increase)	

Marginal Utility	Price Assumption Ranges	
Natural Gas	(Rate 5)	\$6.54 per GJ
Electricity (*)		\$.080 per kWh

(*) \$/kWh includes the marginal impact on peak monthly demand and new General Service Part 2 Energy Charge

Request:

7.1 Are there any incorrect assumptions in the above information?

Response:

The Delta School District Project will be submitted for acceptance as a rate in accordance with the requirements outlined in BCUC Order No. G-141-09. With the exception of accuracy of the



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amount of EEC funding, this question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

With regards to the EEC funding amount noted above please refer to the response to ESAC IR 2.6.5.

7.2 In response to BCUC IR 1.87.1, it was noted that the Lower Mainland/Inland after-tax weighted average cost of capital (WACC) was 6.76%. Please confirm what this equals for a pre-tax WACC? In FEI's view, are these the appropriate WACCs for a project like the DSD?

Response:

Please refer to the response to ESAC IR 2.7.1.

The pre-tax WACC of 9.01% for 2013 can be calculated as follows:

- = (2013 after tax WACC) / (1 Tax Rate)
- = 6.76% / (1 25.0%)
- = 9.01%
- 7.3 What is the appropriate depreciation rate for the assets used in the DSD project? What is the approximate average depreciation rate for these assets?

Response:

Please refer to the response to ESAC IR 2.7.1.



8.0 Pre-Existing Geo-Exchange Assets

Reference: FortisBC Presentation CDEA-IDEA Conference,

June 2011, Toronto, Ontario

"Existing FortisBC discrete assets:
•Approx 60 geo-exchange systems
•Operating since 2007; approx \$8 million assets"

Reference: Response to CEC IR 1.4.1 & BCUC IR 1.78.1

8.1 How many of the above noted systems would fall under FEI's current definition of Alternative Energy Systems (or Thermal Energy Services) requiring regulated tariffs as per the 2010/2011 RRA and NSA?

Response:

This response deals with the responses to ESAC IRs 2.8.1 to 2.8.7.

These questions are not relevant to the present proceeding, which is concerned with setting natural gas rates.

8.2 How many of these systems were submitted to the BCUC for tariff approval at the time they were acquired or developed? Please provide any Commission Order numbers in relation to these approvals.

Response:

Please refer to the response to ESAC IR 2.8.1.

8.3 Have any of these systems or related assets been transferred to FEI? If not, is this being contemplated in the foreseeable future?



Please refer to the response to ESAC IR 2.8.1.

8.4 Which of these systems received a CPCN from the Commission? Please provide the applicable Commission orders granting each such CPCN.

Response:

Please refer to the response to ESAC IR 2.8.1.

8.5 Please provide the applicable approved Schedule 12A for each of these systems. If there is no Schedule 12A applicable to any of these systems, please explain why such schedules do not exist.

Response:

Please refer to the response to ESAC IR 2.8.1.

8.6 Have there been any amendments to the *Utilities Commissions Act* (the "UCA") since these system were acquired or developed that have caused FEI to change its opinion as to whether or not these systems should be characterized as "public utilities" under the UCA requiring regulated tariffs.

Response:

Please refer to the response to ESAC IR 2.8.1.

8.7 Where in the 2012-13 RRA are the revenues and expenditures for these systems set forth?



FortisBC Energy Utilities (comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc.) (FEVI), FortisBC Energy (Whistler) Inc. (FEW), and FortisBC Energy Inc. Fort Nelson Service Area (Fort Nelson) 2012-2013 Revenue Requirements and Natural Gas Rates Application	Submission Date: August 19, 2011
Response to Energy Services Association of Canada ("ESAC") Information Request ("IR") No. 2	Page 35

Please refer to the response to ESAC IR 2.8.1.

8.8 Do these systems make a specific contribution to the natural gas cost of service in excess of the \$0.5 million referred to in the IR responses referenced above?

Response:

Yes, in excess of the \$0.5 million from the Thermal Energy Services Deferral Account, under the continuing services arrangement between FEI and FortisBC Alternative Energy Services Inc. (formerly Terasen Energy Services Inc.), the FEI have forecast an estimated recovery of \$200 thousand for 2012 and \$206 thousand for 2013 for operation and administration of the assets owned by FortisBC Alternative Energy Services Inc.

Attachment 1.1

(Provided in electronic format only due to document size and in order to conserve paper)

										Р	ROGRAM									ALTERN	IATE				N	IET PRESENT	VALUE							BENEFI	T/COST									PARAN	IETERS					
ew Initiative program	s - Geoexchang	e Average SCT						cos	TS (\$000)							SAVIN	IGS (GJ)		LIFE	Impa	ct	Levelized Cost	Utility Bene	fits (Costs)	Particip	oant Benefits	s (Costs)	Р	rogram Net	Savings			Participa	ant						UTILI	Y					PART	TICIPANT			
	FEI			Utility			Р	artners											Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Ga	Alternat Energy		Natural	Gas Total Cos	ts Total Bene	fits Benefit,	t/Cost Natural	Gas	TRC Net	Benefits Gas		Natural as Supply	Alternate Discount Rate	Alternate Supply	Discount Rate	Natural Gas NPV	Carbon Tax NPV	Alternate Energy NPV	e Alternate Capacity NPV	e Natural Ga Y Tariff		ariff Capacity 1
			Incentives	Administratio	n Total	Incenti	ves Adn	ninistration	Total	Participant	Total	% Utility	% Partner	% Participa	nt Gro	ss Net-te	o-Gross	Net		MWh	kW		(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	/ (\$'000s	;) (\$'000	5)	Rate Im	oact SC	т (\$'0			\$/GJ		\$/kWh		\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/GJ	\$/kV	h \$/kW/
		Labe	В	с	D	E		F	G	н	I	J	к	L	м	1	N	0	Р	Q	R	s	т	U	v	w	x	Y	z	AA	AB	AC	AD	AE	E AF	AG	G A	м	AI	AJ	АК	AL	AM	AN	AO	AP	AQ	AR	AS	AT
	So	ource Sheet or Calculation	Program	Program	B+C	Progra	im I	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Prog	ram Pro	gram	MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	ΜΧΝΧΑΟ	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q	N) PV(AK,P,-R	:) T/D	H>0, (V+W)<0 H<0, (V+W X)>0, AD//	'AC T/(V+)) (T+U	י/(L	·U)-I Ir	nput	Program	Input	Input	Input	PV(AM,P,- InputD25)	Input	PV(AM,P,- InputD28)	PV(AM,P,- InputD29)	Input	Inpu	Inpu
SIDENTIAL:	2011																																																	
Geoexchange - Average			()	30	30	0	0		310	34	99	0	% 9	1%	3,330	100%	3,330	20	-260	-	1	1,030	(603)	495	74	(319)) 49,54	-3,	362	- 3	34.3 3	10 2	:50	0.8	2.0	1.3	88 3.	.00%	238.01	3%	1.79	3.0%	148.76	22.35	5 1.2	23 0.0	00 9.99	999 0.0	83
		Total Residential)	30	30	0	0		0 310	34	0 99		- 9	1%	3.330		3.330		-260	0	1	1.030	(603)	495	74	(319)) 49.54	3 (3.8	62) N	/A 3	4.3 3	10 2	50	0.8	2.0	1.3	88	1.6	217										

	D			- I	- I					K		N4	N	0		0		0			14	10/	v	V	7							A.C.	A11	
1 UTILITY	В	FORTIS BC	D	E	F	G	н		J	К	L	М	Ν	0	P	Q	ĸ	5	I	U	V	W	X	Y	Ζ	AA	AB	AC	AD	AE	AF	AG	AH	AI
2																																		
3																																		
4		Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
6	NATURAL GAS	Units																																
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28
8 1		Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
10	carbon tax Distribution adder	\$ per GJ \$ per GJ	0.00 0.16	0.00 0.16		0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00
11	Total incremental cost of gas including	-	15.44	15.44		15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	1	1	15.28
12 2	GDP Deflator		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13 3 14 4	Incremental Cost of Gas (Real) Net Present Value -2010		\$15.44	\$15.44 \$29.54	\$15.44 \$43.67	\$15.44 \$57.39	\$15.44 \$70.71	\$15.44 \$83.64	\$15.44 \$96.20	\$15.44 \$108.38	\$15.44 \$120.22	\$15.44 \$131.71	\$15.44 \$142.86	\$15.44 \$153.69	1 1	\$15.44 \$174.41	\$15.44 \$184.32	\$15.44 \$193.94		\$15.44 \$212.35	\$15.44 \$221.16		\$15.44 \$238.01	\$15.44 \$246.07	\$15.44 \$253.89		\$15.44 \$268.86	\$15.44 \$276.02	\$15.44 \$282.97	\$15.44 \$289.72	\$15.44 \$296.27	\$15.44 \$302.63	\$15.44 \$308.81	\$15.28 \$314.74
15 5	Net Present Value -2011			φ29.01	\$29.54	\$43.67	\$57.39	\$70.71	\$83.64	\$96.20	\$108.38	\$120.22	\$131.71	\$142.86		\$164.20	\$174.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07	\$253.89	\$261.48	\$268.86	\$276.02	\$282.97	\$289.72	\$296.27	\$302.63	\$308.74
16 6	Net Present Value -2012					\$29.54	\$43.67	\$57.39	\$70.71	\$83.64	\$96.20	\$108.38	\$120.22	\$131.71	\$142.86	\$153.69	\$164.20	\$174.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07	\$253.89	\$261.48	\$268.86	\$276.02	\$282.97	\$289.72	\$296.27	\$302.56
17																																		
19	ELECTRICITY																																	
20	Incremental Cost of Elec	\$ Per kWh	\$0.12																															
21	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00																															
23																																		
24																																		
25 RETAIL				~						1.5.11.11																								
26	Residential Retail		Rate	Customers		789,928 To	tal Customers in I	BC	80,000 Tc	tal Residential a	nd Commercial Cus	stomers on VI																						
28		TGI \$ Per MJ	\$0.0100	640		712,304 To	tal Residential Cu	stomers in BC																										
29		GVI \$ Per MJ	\$0.0143	72																														
30	Electric	ity \$ Per MJ	\$0.0230 \$0.0827	1 511		1.511.435 To	tal BCH Residenti	al Customers in B0	C		89%																							
32		sity \$ per kW per year	<i>ф0.0021</i>	19011		1,511,155 10					07/10																							
33	Commercial Retail		#0.000.1																															
34		TGI \$ Per MJ GVI \$ Per MJ	\$0.0094 \$0.0169	8		77,624 To	tal Commercial Cu	ustomers in BC																										
36	Electric		\$0.0214																															
37 38	Electric		\$0.0769	190		189,764 To	tal Light Industria	l and Commercial	Customers in BC																									
38	Electric	sity \$ per kW per year	\$52.0000	15																														
40 TAX																																		
41		Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
42 1	C. L.	Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	-	28	29	30
43 2 44 3	Carbon Carbon	\$ Per tonne \$ Per GJ		\$20.00 \$0.9976	\$25.00 \$1.2470	\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00	\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00 \$1.4964		\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00	\$30.00 \$1.4964														
45 4	GDP Deflator			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
42 1 43 2 44 3 45 4 46 5 47 6 48 7 49 8 50 50	Carbon (Real)			\$1.00	\$1.25 \$2.14	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50
48 7	Net Present Value -2010 Net Present Value -2011				\$2.14	\$3.51 \$2.62	\$4.84 \$3.99	\$6.13 \$5.32	\$7.39 \$6.61	\$8.60 \$7.86	\$9.78 \$9.08	\$10.93 \$10.26	\$12.05 \$11.41	\$13.13 \$12.52	\$14.18 \$13.60	\$15.19 \$14.65	\$16.18 \$15.67	\$17.14 \$16.66	\$18.08 \$17.62	\$18.98 \$18.55	\$19.86 \$19.46	\$20.71 \$20.34	\$21.54 \$21.19	\$22.35 \$22.02	\$23.13 \$22.82	\$23.89 \$23.61	\$24.62 \$24.36	\$25.34 \$25.10	\$26.03 \$25.81	\$26.71 \$26.51	\$27.36 \$27.18	\$27.99 \$27.84	\$28.61 \$28.47	\$29.21 \$29.09
49 8	Net Present Value -2012						\$2.86	\$4.23	\$5.56	\$6.85	\$8.11	\$9.32	\$10.50	\$11.65		\$13.85	\$14.90	\$15.91	\$16.90	\$17.86	\$18.80	\$19.70	\$20.58	\$21.43	\$22.26	\$23.07	\$23.85	\$24.61	\$25.34	\$26.06	\$26.75	\$27.42	\$28.08	\$28.71
50 51	Discount Rate (real) ¹																																	
52	TERASEN GAS																																	
53	Rate of Inflat																																	
54 55		TGI 3.00%																																
56	BC HYDRO	GVI 3.00%																																
57	Rate of Inflat																																	
58	BC Hy																																	
59 60	Footnote 1: Source LR 0703																																	
61																																		
62		S	HEET LAB	ELS																														
63 New Constructio	n Geoexchange - Average		ASEBOAR	<u>ן</u>																														
65			IEATPUMP	-																														
66																																		

FORTIS BC

	A					
Measure Data for Geoexch	nange - Avera	age				
PER MEASURE			Utility Incentive to the participant	partner incentive		
Incremental Cost	\$ 309,667					
Total Incentive	A 200 CC7			\$-		
Participant	\$ 309,667					
Annual Impact Per Measure Energy Savings per installation	3330.1	GJ		Average Annnual Energy Savin	gs ner Measure	
Free Rider Rate / Net-to-Gross	0%	1.00		Net-to-Gross	gs per measure	
Alternate Energy Impact	-935	GJ	-259,611	kWh		
Alternate Capacity Impact		kW/a				
Measure Lifetime	20		Estimated lifespan of me	easure		
		, , , , , , , , , , , , , , , , , , , ,				
ANNUAL ACTIVITY	2009 NPV	<u>Total</u>	<u>2010</u>	<u>2011</u>	2012	Explanatory Notes
Number of Installations						
	1	1	0	1		Estimated Participatation
Impact						
Gross Energy Savings (GJ)	3,139		0	3,330	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	3,139		0	3,330	0	Gross Energy Savings less Free Riders
	-244,708	-259,611	0	-259,611	0	
Alternate Energy Impact (Increase) (kWh)		235,011	0	-239,011	0	Other Utility Billed energy impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a)	\$0.00	-	Ū	-239,011	0	Other Utility Billed capacity impact Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a)		-		-239,011	0	
		-		-239,011	0	
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary		<u>\$ Total</u>	<u>2010</u>	<u>2011</u>	2012	
Alternate Capacity Impact (Increase) (kW/a)	\$0.00	-				
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary	\$0.00	- <u>\$ Total</u>	<u>2010</u> \$238.01	<u>2011</u> \$238.01	<u>2012</u> \$238.01	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements	\$0.00	- <u>\$ Total</u>	<u>2010</u> \$238.01	2011	<u>2012</u> \$238.01	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ	\$0.00	- <u>\$ Total</u>	<u>2010</u> \$238.01	<u>2011</u> \$238.01	<u>2012</u> \$238.01	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases	\$0.00	- <u>\$ Total</u> <u>\$ 792,590</u>	<u>2010</u> \$238.01	<u>2011</u> \$238.01	<u>2012</u> \$238.01	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs	\$0.00	- <u>\$ Total</u> <u>\$ 792,590</u>	<u>2010</u> \$238.01 \$	<u>2011</u> \$238.01 \$792,590	<u>2012</u> \$238.01 \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration	\$0.00 <u>2009 NPV</u> \$ 792,590	- <u>\$ Total</u> <u>\$ 792,590</u> \$ - <u>\$ 30,000</u>	<u>2010</u> \$238.01 \$ - \$ - \$ -	<u>2011</u> \$238.01 \$792,590 \$- \$ 30,000	<u>2012</u> \$238.01 <u>\$</u> - \$-	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal	\$0.00	- <u>\$ Total</u> <u>\$ 792,590</u> \$ - <u>\$ 30,000</u>	<u>2010</u> \$238.01 \$ - \$ - \$ -	<u>2011</u> \$238.01 \$792,590 \$ \$ 30,000	<u>2012</u> \$238.01 <u>\$</u> - \$-	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs	\$0.00 <u>2009 NPV</u> \$ 792,590	- <u>\$ Total</u> <u>\$ 792,590</u> \$ - <u>\$ 30,000</u>	<u>2010</u> \$238.01 \$ - \$ - \$ -	<u>2011</u> \$238.01 \$792,590 \$- \$ 30,000	<u>2012</u> \$238.01 <u>\$</u> - \$-	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal	\$0.00 <u>2009 NPV</u> \$ 792,590	- <u>\$ Total</u> <u>\$ 792,590</u> \$ - <u>\$ 30,000</u>	<u>2010</u> \$238.01 \$ - \$ - \$ -	<u>2011</u> \$238.01 \$792,590 \$- \$ 30,000	<u>2012</u> \$238.01 <u>\$</u> - \$-	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration	\$0.00 <u>2009 NPV</u> \$ 792,590 \$ 28,278	- <u>\$ Total</u> <u>\$ 792,590</u> <u>\$ -</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ -</u>	<u>2010</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	<u>2011</u> \$238.01 \$792,590 \$- \$30,000 \$30,000 \$- \$	<u>2012</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration	\$0.00 <u>2009 NPV</u> \$ 792,590	- <u>\$ Total</u> <u>\$ 792,590</u> \$ - <u>\$ 30,000</u>	<u>2010</u> \$238.01 \$ - \$ - \$ -	<u>2011</u> \$238.01 \$792,590 \$- \$ 30,000	<u>2012</u> \$238.01 <u>\$</u> - \$-	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs	\$0.00 <u>2009 NPV</u> \$ 792,590 \$ 28,278	- <u>\$ Total</u> <u>\$ 792,590</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u>	2010 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$238.01 \$792,590 \$- \$30,000 \$30,000 \$ \$- \$- \$- \$- \$- \$- \$- \$- \$-	<u>2012</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Partner Program Costs Incremental Cost	\$0.00 2009 NPV \$ 792,590 \$ 28,278 \$	- <u>\$ Total</u> <u>\$ 792,590</u> <u>\$ -</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ 30,000</u>	2010 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$238.01 \$792,590 \$- \$- \$30,000 \$30,000 \$- \$- \$- \$- \$- \$- \$- \$- \$- \$-	2012 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal	\$0.00 <u>2009 NPV</u> \$ 792,590 \$ 28,278	- <u>\$ Total</u> <u>\$ 792,590</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u>	2010 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$238.01 \$792,590 \$- \$30,000 \$30,000 \$ \$- \$- \$- \$- \$- \$- \$- \$- \$-	2012 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net	\$0.00 2009 NPV \$ 792,590 \$ 28,278 \$	- <u>\$ Total</u> <u>\$ 792,590</u> <u>\$ -</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>5 5 5 5 5 5 5 5 5 5 5 5 5 5 5 5 5 5 5 </u>	2010 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$238.01 \$792,590 \$- \$30,000 \$30,000 \$30,000 \$- \$- \$- \$- \$- \$- \$- \$309,667 \$309,667	<u>2012</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Partner Program Costs Incremental Cost Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases)	\$0.00 2009 NPV \$ 792,590 \$ 28,278 \$	- <u>\$ Total</u> <u>\$ 792,590</u> <u>\$ -</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>5 5 5000000000000000000000000000000000</u>	2010 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$238.01 \$792,590 \$- \$- \$30,000 \$30,000 \$30,000 \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$- \$30,000 \$- \$- \$30,000 \$- \$- \$30,000 \$- \$- \$- \$- \$- \$- \$- \$- \$- \$-	<u>2012</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases) Capacity (Purchases)	\$0.00 2009 NPV \$ 792,590 \$ 28,278 \$ \$	- <u>\$ Total</u> <u>\$ 792,590</u> <u>\$ -</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u>	2010 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$238.01 \$792,590 \$- \$- \$30,000 \$30,000 \$30,000 \$- \$- \$- \$- \$- \$- \$- \$- \$- \$-	2012 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Partner Program Costs Incremental Cost Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases)	\$0.00 2009 NPV \$ 792,590 \$ 28,278 \$	- <u>\$ Total</u> <u>\$ 792,590</u> <u>\$ -</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$ 309,667</u> <u>\$ 309,667</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u>	2010 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$238.01 \$792,590 \$- \$- \$30,000 \$30,000 \$30,000 \$30,000 \$- \$- \$- \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$30,000 \$- \$- \$30,000 \$- \$- \$30,000 \$- \$- \$30,000 \$- \$- \$- \$- \$- \$- \$- \$- \$- \$-	2012 \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact

Fortis BC																																														
	-								PROGRAM				1				ALTER	RNATE		-		,	NET PRESENT	VALUE					1		BENEFIT/CO	ST		1						PARAM	IETERS					
New Initiative Program Average TRC	ms - Geoexchange					0	OSTS (\$000)							SAVINGS (GJ))	LIFE	Imp	pact	Levelized Cost	Utility Be	nefits (Costs)	Partici	pant Benefits	(Costs)	Prog	ram Net Sa	wings			Participant						UTII	YTL	ļ				PARTICI	JPANT			
			Utility			Partners										Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternate Supply	Discount Rate		Carbon	Alternate Energy NPV	Alternate Capacity NPV		Energy Tariff	Capacity Tariff
		Incentives	Administration	Total	Incentives	Administration	Total	Participan	t Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWh	kW		(\$'000s)	(\$'000s)	(\$*000s)	(\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	(\$*000s)	(\$'000s)		Rate Impact	Total Resource	(\$'000s)		\$/GJ		\$/kWh		\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/GJ	\$/kWh	\$/kW/a
	Label	в	c	D	E	F	G	н		1	к	L	м	N	0	Р	Q	R	s	т	C C	v	w	x	¥	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	e e	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
Sou	urce Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	нл	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q×N×AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-i	Input	Program	Input	Input	Input	PV(AM,P,- inputD25)	Input	PV(AM,P,- InputD28)	PV(AM,P,- InputD29)	Input	Input	Input
201 <u>Schools</u> Geoexchange-Avera		0	30	30	0	0		0 31	D 34	99	5 0%	91%	3,330	100%	3,330	20	(260)	-	- 1	372	(326)	349	53	(225)	34,872	(2,719)) -	12.4	310	176	0.6	1.0	0.1	(293)	7.15%	111.84	7%	% 1.26	7.2%	104.71	15.79	0.87	0.00	9.999	0.083	-

^	D	<u>^</u>	D	E I	F	G	н		J	к		М	N	0	Р	Q	R	· ·	_ T	U	V	W	х	Y	7	AA	AB	AC	AD	AE	AF	AG	AH	AI
	В	Fortis BC	D	E	F	G	п	1	J	ĸ	L	IVI	IN	0	P	Q	ĸ	5		U	v	VV	~	T	Z	AA	AB	AC	AD	AE	AF	AG	АП	AI
		Totasbe																																
3	1		1]												1			1		1			1		1	
4		Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5	NATURAL GAS	Units																																
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$5.50	\$6.17	\$6.81	\$7.35	\$7.87	\$8.26	\$8.56	\$8.78	\$8.99	\$9.19	\$9.40	\$9.60	\$9.81	\$10.03	\$10.25	\$10.47	\$10.70	\$10.93	\$11.17	\$11.42	\$11.67	\$11.92	\$12.19	\$12.45	\$12.73	\$13.01	\$13.29	\$13.58	\$13.88	\$14.19	\$14.50	\$14.82
8 1	· ·	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
9	carbon tax	\$ per GJ	0.75	1.00	1.25	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50		1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
11	Distribution adder Total incremental cost of gas including ca	\$ per GJ arbon	0.16	0.16 7.32	0.16 8.21	0.16 9.01	0.16 9.52	0.16 9.92	0.16 10.22	0.16 10.43	0.16 10.64	0.16 10.85	0.16 11.05	0.16 11.26	0.16 11.47	0.16 11.68	0.16 11.90	0.16 12.13		0.16 12.59	0.16	0.16 13.07		0.16 13.58	0.16 13.84	0.16 14.11	0.16 14.38	0.16 14.66	0.16 14.95	0.16 15.24	0.16 15.54	0.16 15.84	0.16 16.15	16.31
12 2	GDP Deflator		1.00	1.00			1.00	1.00		1.00	1.00		1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00
13 3	Incremental Cost of Gas (Real)		\$6.41	\$7.32			\$9.52	\$9.92		\$10.43	\$10.64	910.05	\$11.05			\$11.68	\$11.90	\$12.13	\$12.35	\$12.59	\$12.83	\$13.07	\$13.32	\$13.58	\$13.84	\$14.11	\$14.38	\$14.66	\$14.95	\$15.24	\$15.54	\$15.84	\$16.15	\$16.31
14 4	Net Present Value -2010 Net Present Value -2011			\$12.36	\$19.03 \$13.99		\$32.61 \$28.54	\$39.16 \$35.56		\$51.47 \$48.75	\$57.19 \$54.87		\$67.80 \$66.24	\$72.71 \$71.51	\$77.39 \$76.51		\$86.05 \$85.80	\$90.07 \$90.10	\$93.89 \$94.20	\$97.52 \$98.09	\$100.98 \$101.79	\$104.26 \$105.31	\$107.39 \$108.66	\$110.36 \$111.84	\$113.19 \$114.87	\$115.88 \$117.75	\$118.43 \$120.49	\$120.87 \$123.10		\$125.39 \$127.95	\$127.49 \$130.19	\$129.48 \$132.33	\$131.38 \$134.37	\$133.17 \$136.28
16 6	Net Present Value -2012				<i>Q13.77</i>	\$15.51	\$23.25	\$30.78		\$44.91	\$51.47		\$63.65	\$69.29	\$74.66		\$84.61	\$89.22	\$93.61	\$97.78	\$101.74	\$105.51	\$109.10	\$112.51	\$115.76	\$118.85	\$121.79	\$124.58		\$129.77	\$132.18	\$134.47	\$136.65	\$138.70
17																																		
2 3 4 5 6 7 8 1 9 10 11 12 2 13 3 14 4 15 5 16 6 17 18 19 20 21 22 23 24 25 RETAIL 26 27 28 29 30 31 34 34 45 5 5 16 6 17 18 19 20 21 22 23 33 34 35 36 37 38 39 40 7 7 8 7 7 8 7 7 8 7 7 8 7 7 8 7 7 7 8 7 7 7 8 7 7 7 8 7 7 7 7 8 7 7 7 8 7 7 7 8 7 7 7 8 7 7 7 8 7 7 7 7 7 8 7 7 7 7 7 7 7 7 7 7 7 7 7	ELECTRICITY		+ +																															
20	Incremental Cost of Elec	\$ Per kWh	\$0.12																															
21	Incremental Cost of E Capacity		\$170.00																															
22			+																															
23	1																																	
25 RETAIL		L																																
26			Rate	Customers		789,928	Total Customers i	n BC	80,000 To	tal Residential and	d Commercial C	ustomers on VI																						
27	Residential Retail		00.0100	000's																														
28		GI \$ Per MJ	\$0.0100 \$0.0143	640 72		712,304	Total Residential C	Customers in BC																										
30	Electricit		00.0115	14																														
31		ty \$ per kWh	\$0.0827	1,511		1,511,435	Total BCH Reside	ntial Customers in	n BC		89%																							
32	Electricit Commercial Retail	ty \$ per kW per year																																
34		GI \$ Per MJ	\$0,0094	78		77.624	Total Commercial	Customers in BC																										
35		VI \$ Per MJ	\$0.0169	8																														
36		ty \$ Per MJ	\$0.0214	100																														
37		ty \$ per kWh ty \$ per kW per year	\$0.0707	190		189,764	Total Light Indust	ial and Commerc	ial Customers in BC																									
39		<u></u>																																
40 TAX																																		
41 42 1		Year	2009	2010	2011	2012	2013	2014		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
42 1 43 2	Carbon	Year \$ Per tonne		0 \$20.00	1 \$25.00	2 \$30.00	3 \$30.00	4 \$30.00	5	6 \$30.00	7	8 \$30.00	9 \$30.00	10 \$30.00	11 \$30.00	12 \$30.00	13 \$30.00	14 \$30.00	15 \$30.00	16 \$30.00	17 \$30.00	18 \$30.00	19 \$30.00	20 \$30.00	21 \$30.00	22 \$30.00	23 \$30.00	24 \$30.00		26 \$30.00	27 \$30.00	28 \$30.00	29 \$30.00	30 \$30.00
44 3	Carbon	\$ Per GJ		\$0.9976	\$1.2470		\$1.4964	\$1.4964		\$1.4964	\$1.4964		\$1.4964	\$1.4964			\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964
45 4	GDP Deflator			1.00	1.00	1.0.0	1.00	1.00		1.00	1.00						1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00
46 5 47 6	Carbon (Real) Net Present Value -2010		+ +	\$1.00	\$1.25	\$1.50 \$3.23	\$1.50 \$4.37	\$1.50 \$5.43		\$1.50 \$7.34	\$1.50 \$8.20		\$1.50 \$9.75	\$1.50 \$10.45	\$1.50 \$11.11	\$1.50 \$11.72	\$1.50	\$1.50 \$12.82	\$1.50 \$13.31	\$1.50 \$13.78	\$1.50 \$14.21	\$1.50	\$1.50 \$14.99	\$1.50 \$15.34	\$1.50 \$15.67	\$1.50 \$15.97	\$1.50 \$16.26	\$1.50 \$16.52		\$1.50 \$17.00	\$1.50 \$17.22	\$1.50 \$17.42	\$1.50 \$17.61	\$1.50 \$17.79
48 7	Net Present Value -2010				92.02	\$2.47	\$3.68	\$4.82		\$6.87	\$7.79		\$9.45	\$10.20	\$10.90	+	\$12.17	\$12.74	\$13.27	\$13.76	\$14.23	\$14.66	\$15.06	\$15.44	\$15.79	\$16.12	\$16.42	\$16.71		\$17.22	\$17.45	\$17.67	\$17.87	\$18.06
49 8	Net Present Value -2012						\$2.70	\$3.92	\$5.05	\$6.11	\$7.10	\$8.02	\$8.88	\$9.69	\$10.44	\$11.14	\$11.79	\$12.40	\$12.97	\$13.50	\$14.00	\$14.46	\$14.89	\$15.29	\$15.67	\$16.02	\$16.35	\$16.65	\$16.94	\$17.21	\$17.45	\$17.69	\$17.90	\$18.10
50 51	Discount Rate (real) ¹		+ +																															
52	TERASEN GAS		+ +																															
53	Rate of Inflation																																	
54	T	GI 7.15%	+ +			├																												
56	BC HYDRO	/.1.370	+ +																															
57	Rate of Inflation																																	
58	BC Hyd																																	
59	Footnote 1: Source LR 0705		+ +																															
61	TOURIDE T. SOURCE EN UTUE		+ +																															
62																																		
63			+ +																															
65			+ +						<u> </u>																									
66																																		

Fortis BC			only ente	r in boxes mark	ed in blue	9
Schools			-			
NEW						
Measure Data for Geoexcl	nange- Av	erage				
		0				
PER MEASURE			Utility Incentive to	partner incentive		
			the participant	•		
Incremental Cost	\$ 309,66	57				
Total Incentive	\$-					
Participant	\$ 309,66	57				
Annual Impact Per Measure						
Energy Savings per installation	3330.1	GJ		Average Annnual Energy Savi	ngs per Measure	
Free Rider Rate / Net-to-Gross		1.00		Net-to-Gross		
Alternate Energy Impact	-935	GJ	-259,611	kWh		
Alternate Capacity Impact		kW/a				
Measure Lifetime	20	Years	Estimated lifespan of m	easure		
ANNUAL ACTIVITY	2010 NPV	Tota	l 2010	2011	2012	Explanatory Notes
Number of Installations	2010 NPV	Tota	2010	<u>2011</u>	2012	
		1	1 0	1		Estimated Participatation
Impact		1		1		
Gross Energy Savings (GJ)	3,1	3,330	0 0	3,330	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	3,1			3,330	0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	(242,2			(259,611)	0	Other Utility Billed energy impact
Alternate Capacity Impact (Increase) (kW/a)	\$0.		-	(200,011)	0	Other Utility Billed capacity impact
Alternate capacity impact (increase) (kw/a)					I	other other blied capacity impact
Benefit Cost Summary						
benefit cost summary	2010 NPV	\$ Total	2010	2011	2012	
Avoided Revenue Requirements	2010101	<u>9 10tur</u>	2010	2011	2012	-
PV \$ per GJ			\$107.39	\$111.84	\$115.70	6
Energy Purchases	\$ 372,4	43 \$ 372,443		\$ 372,443		
Utility Program Costs		· · · · ·		. <u> </u>	<u>-</u>	<u>-</u>
DSM Incentives		Ś	- \$ -	\$-	\$-	
Administration		\$ 30,000		\$ 30,000		
Subtotal	\$ 27,9			\$ 30,000	Ś -	
Partner Program Costs	γ 21,9.	50,000	, _Y -	÷ 50,000		-
DSM Incentives		Ś	- \$ -	\$ -	ś -	
Administration		ś -	\$ -	\$ -	\$ - \$	
Subtotal	ś-	5 -		<u> </u>	\$ -	•
Participants' Net Costs	- ڊ	ې -	- ډ	- ب	- ڊ	-
Incremental Cost		\$ 309,667	7\$-	\$ 309,667	\$-	
	ć 200 0		-	·		-
Subtotal	\$ 289,0	03 \$ 309,667	7 \$ -	\$ 309,667	ş -	_
Alternate Savings - Net		ć (226.22)	s) ć	ć /226.220	ć	\$1.257 DV \$ por kWh
Energy (Purchases)		\$ (326,226		\$ (326,226) \$ -		\$1.257 PV \$ per kWh
Capacity (Purchases)		<u> </u>	<u>\$</u> -		<u>\$</u> -	PV\$ per kW/a
Subtotal Total Resource Net Benefit (Cost)	\$ (326,2			\$ (326,226) \$ (293,450)		
	\$ (270,7		Ŷ	1		Avoided Revenue Requirement less Utility less Partners less Participan
Utility Levelized Cost per GJ (Lifetime)	\$ 9	9.7	\$-	\$ 9.7	\$ -	Informational (for comparison with supply options)

IRTIS BC								PR	OGRAM								ALTI	RNATE					NET PRESEN	IT VALUE							ENEFIT/COST									PARAN	AETERS				
w Initiative Programs - Geoexchange Elementary SCT						COSTS (:	\$000)							SAVINGS (ii)	LIFE	In	pact	Levelized Cost	Utility Ber	efits (Costs) Partic	ipant Benefi	its (Costs)	Pr	ogram Net S	avings			Participant						UTIL	.ITY					PARTIC	IPANT		
FEI		Utility			Partn	ners										Years	Energy	Capacity	(\$/GJ)	Program	Alternate	e Program	Carbon Ta	ax Alternat	* Natural Ga	Alternate Energy		Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternate Supply	Discount Rate	Natural Gas NPV	Carbon Tax NPV	Alternate Energy NPV	Alternate Capacity NPV	Natural Gas Tariff	Energy Tariff
	Incentives	Administration	Total	Incentives	Administ	tration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gros	s Net		MWb	kW		(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	(\$'000s)	(\$'000s)		late Impact	SCT	(\$'000s)		\$/GJ		\$/kWh		\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/GJ	\$/kWh
Label	в	c	D	E	F		G	н	1	1	к	L	м	N	0	Р	٩	R	s	т	U	v	w	×	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AI	AK	AL	AM	AN	AO	AP	AQ	AR	AS
Source Sheet or Calculation	Program	Program	B+C	Program	Progra	am	E+F	Program	D+G+H	D/I	6/1	н/1	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x A0	N x (QxAP RxAQ)	* PV(AJ,P,-O)	PV(AK,P,-Q*I	N) PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	Input	Program	Input	Input	Input	PV(AM,P,- InputD25)	Input	PV(AM,P,- InputD28)	PV(AM,P,- InputD29)	Input	Input
2011 <u>SIDENTIAL:</u> Geoexchange - Elementary	0	30	30	C)	0	0	167	197	15%	09	85%	1,402	100	6 1,402	20	(153) -	1	434	(356	i) 205	9 31	L (18) 20,858	(2,28	1)	- 14.	5 167	51	0.3	1.8	0.4	(119	3.00%	238.01	3%	1.79	3.0%	148.76	22.35	1.23	0.00	9.999	0.083

· · · ·				-	-	0								~		0		0	-				V		-		40	4.0	40		45	10		
1 UTILITY	В	FORTIS BC	D	E	F	G	Н		J	К	L	М	N	0	Р	Q	R	5		U	V	W	Х	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
2		FORTIS BC																																
3	1	1	1 1					1	L L	1			1		1	1		1	1	1	1	1	1	1	1	1	1		I	1	1	1	1	
4	ļ	Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5		Units																																
6	NATURAL GAS			\$15.28	\$15.28					\$15.28	\$15.28				\$15.28	\$15.28	\$15.28										\$15.28	\$15.28	\$15.28	\$15.28				\$15.28
8 1	Incremental Cost of Gas (nominal)	\$ Per GJ	\$15.28 0	\$15.28	\$15.28	\$15.28 3	\$15.28 4	\$15.28	\$15.28 6	\$15.28	\$15.28	\$15.28 9	\$15.28 10	\$15.28	\$15.28	\$15.28	\$15.28 14	\$15.28 15	\$15.28	\$15.28	\$15.28 18	\$15.28 19	\$15.28 20	\$15.28	\$15.28 22	\$15.28 23	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28 28	\$15.28	\$15.28 30	\$15.28
9	carbon tax	\$ per GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	Distribution adder	\$ per GJ	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16		0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	
11	Total incremental cost of gas including ca GDP Deflator	rbon	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44		15.44	15.44	15.44	15.44 1.00	15.44	15.44	15.44	15.44	15.44	15.44	15.28
13 3	Incremental Cost of Gas (Real)		\$15.44	\$15.44	\$15.44	\$15.44		110.0		1.00 \$15.44	1.00		1.00	\$15,44	1.00	1.00	\$15.44	1.00 \$15.44	\$15.44	\$15.44	1.00 \$15.44	1.00 \$15.44	1.00 \$15.44	1.00 \$15.44	\$15,44	1.00 \$15.44	\$15.44	1.00	1.00 \$15.44	\$15,44	\$15.44	\$15.44	\$15.44	\$15.28
14 4	Net Present Value -2010			\$29.54						\$108.38	\$120.22		\$142.86	\$153.69			\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07		\$261.48	\$268.86			\$289.72	\$296.27	\$302.63	\$308.81	\$314.74
15 5	Net Present Value -2011	_			\$29.54					\$96.20	\$108.38	0.100100	\$131.71	\$142.86	4100107	\$164.20	\$174.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	4210101	\$253.89	\$261.48	0-0000	+=+010=	\$282.97	\$289.72	\$296.27	\$302.63	\$308.74
16 6	Net Present Value -2012	-				\$29.54	\$43.67	\$57.39	\$70.71	\$83.64	\$96.20	\$108.38	\$120.22	\$131.71	\$142.86	\$153.69	\$164.20	\$174.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07	\$253.89	\$261.48	\$268.86	\$276.02	\$282.97	\$289.72	\$296.27	\$302.56
18			-																															
19	ELECTRICITY																																	
20	Incremental Cost of Elec	\$ Per kWh	\$0.12																															
21	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00																															
23																																		
24																																		
3 4 5 6 7 8 1 9 10 11 12 2 13 3 14 4 4 5 5 16 6 17 18 19 20 21 22 23 24 24 25 RETAIL 26 8 8 8 1 9 10 11 12 2 2 2 3 3 14 4 4 5 5 5 5 5 5 5 5 5 5 5 5 5																																		
26	Residential Retail		Rate	Customers		789,928	Total Customers	in BC	80,000 T	otal Residential a	nd Commercial C	ustomers on VI																						
28		GI § Per MJ	\$0.0100	640		712.304	Total Residential	Customers in BC																										
29	та		\$0.0143	72		112,004	roun reconcentur	customers in De																										
30	Electricit		\$0.0230																															
31		y \$ per kWh y \$ per kW per year	\$0.0827	1,511		1,511,435	Total BCH Resid	lential Customers in	BC		89%																							
33	Commercial Retail	y sperkw peryear	1 1																															
34		GI \$ Per MJ	\$0.0094	78		77,624	Total Commercia	l Customers in BC																										
35	TG		\$0.0169	8																														
37	Electricit	y \$ Per MJ y \$ per kWh	\$0.0214 \$0.0769	190		189 764	Total Light Indu	trial and Commerc	ial Customers in BC																									
38		y \$ per kW per year	\$52.0000	15		107,704	TOUR LABIT HUU	and conner	in customers in De																									
39																																		
41		Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018 8	2019	2020	2021	2022	2023 13	2024	2025	2026	2027	2028	2029	2030 20	2031	2032	2033	2034 24	2035	2036 26	2037 27	2038 28	2039 29	2040 30
42 1 43 2	Carbon	Year \$ Per tonne	+ +	\$20.00	\$25.00		-		-	\$30.00	\$30.00	0	\$30.00				\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	18 \$30.00	\$30.00	\$30.00		\$30.00	\$30.00			\$30.00	\$30.00	\$30.00	\$30.00	\$30.00
44 3	Carbon	\$ Per GJ		\$0.9976	\$1.2470					\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964
45 4 46 5	GDP Deflator			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		1.00	1.00		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	100	1.00	1.00	1.00	1.00	1.00
46 5	Carbon (Real) Net Present Value -2010			\$1.00	\$1.25	\$1.50	\$1.50 \$4.84	\$1.50 \$6.13	\$1.50 \$7.39	\$1.50 \$8.60	\$1.50	\$1.50 \$10.93	\$1.50 \$12.05	\$1.50 \$13.13	\$1.50 \$14.18	\$1.50 \$15.19	\$1.50 \$16.18	\$1.50 \$17.14	\$1.50 \$18.08	\$1.50 \$18.98	\$1.50 \$19.86	\$1.50 \$20.71	\$1.50 \$21.54	\$1.50 \$22.35	\$1.50 \$23.13	\$1.50 \$23.89	\$1.50 \$24.62	\$1.50 \$25.34	φ1.50	\$1.50 \$26.71	\$1.50 \$27.36	\$1.50 \$27.99	\$1.50 \$28.61	\$1.50 \$29.21
48 7	Net Present Value -2010				92.14	\$2.62	\$3.99	\$5.32	\$6.61	\$7.86	\$9.08		\$11.41	\$12.52		\$14.65	\$15.67	\$16.66	\$17.62	\$18.55	\$19.46	\$20.74	\$21.34	\$22.02	\$22.82	\$23.61	\$24.36	\$25.10		\$26.51	\$27.18	\$27.84	\$28.47	\$29.09
49 8	Net Present Value -2012						\$2.86	\$4.23	\$5.56	\$6.85	\$8.11	\$9.32	\$10.50	\$11.65	\$12.76	\$13.85	\$14.90	\$15.91	\$16.90	\$17.86	\$18.80	\$19.70	\$20.58	\$21.43	\$22.26	\$23.07	\$23.85	\$24.61	\$25.34	\$26.06	\$26.75	\$27.42	\$28.08	\$28.71
50	Discount Rate (real) ¹		+ +																															
52	TERASEN GAS																																	
53	Rate of Inflatio																																	
54	то		+																														T	
56	TG ¹ BC HYDRO	VI 3.00%	+ +																															
57	Rate of Inflatio	n 2.00%																																
58	BC Hydr	ro 3.00%																																
59	Custome Footnote 1: Source LR 07053																																	
61	Footnote 1: Source LR 07053	1	+ +																															
62			SHEET LABE	ELS																														
63 New Constructio																																		
64	Geoexchange - Elementary	0	BASEBOARD	D																														
66	+	0	REATPUMP																															
	1					· · · · · · · · · · · · · · · · · · ·		L																										

FORTIS BC	
Schools	

NEW						
Measure Data for Geoexch	ango - Flom	ontary				
Measure Data for Geoexci	lange - Lienn	entary				
PER MEASURE			Utility Incentive to the participant	partner incentive		
Incremental Cost	\$ 166,631					
Total Incentive				\$-		
Participant	\$ 166,631					
Annual Impact Per Measure						
Energy Savings per installation	1402.0	GJ		Average Annnual Energy Savir	igs per Measure	
Free Rider Rate / Net-to-Gross	0%	1.00		Net-to-Gross		
Alternate Energy Impact	-552	GJ	-153,333	kWh		
Alternate Capacity Impact		kW/a				
Measure Lifetime	20	Years	Estimated lifespan of me	easure		
ANNUAL ACTIVITY	2009 NPV	Total	2010	2011	2012	Explanatory Notes
Number of Installations						
	1	1	0	1		Estimated Participatation
Impact		1				
Gross Energy Savings (GJ)	1,322	1,402	0	1,402	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	1,322	1,402	0	1,402	0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a)	(144,531) \$0.00		0	(153,333)	0	Other Utility Billed capacity impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh)	(144,531)					Other Utility Billed energy impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a)	(144,531)					Other Utility Billed energy impact
Alternate Energy Impact (Increase) (kWh)	(144,531) \$0.00	(153,333)	0	(153,333)	0	Other Utility Billed energy impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary	(144,531)					Other Utility Billed energy impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements	(144,531) \$0.00	(153,333)	0 <u>2010</u>	(153,333) <u>2011</u>	0 <u>2012</u>	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ	(144,531) \$0.00 <u>2009 NPV</u>	(153,333) - <u>\$ Total</u>	0 <u>2010</u> \$238.01	(153,333) 2011 \$238.01	0 <u>2012</u> \$238.01	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements	(144,531) \$0.00	(153,333) - <u>\$ Total</u>	0 <u>2010</u> \$238.01	(153,333) <u>2011</u>	0 <u>2012</u> \$238.01	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ	(144,531) \$0.00 <u>2009 NPV</u>	(153,333) - <u>\$ Total</u>	0 <u>2010</u> \$238.01	(153,333) 2011 \$238.01	0 <u>2012</u> \$238.01	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases	(144,531) \$0.00 <u>2009 NPV</u>	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u>	0 <u>2010</u> \$238.01	(153,333) 2011 \$238.01	0 <u>2012</u> \$238.01	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs	(144,531) \$0.00 <u>2009 NPV</u>	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u>	0 <u>2010</u> \$238.01 \$ <u>-</u>	(153,333) <u>2011</u> \$238.01 \$333,687 \$	0 <u>2012</u> \$238.01 \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 30,000</u>	0 <u>2010</u> \$238.01 \$ - \$ - \$ -	(153,333) <u>2011</u> \$238.01 \$333,687 \$	0 <u>2012</u> \$238.01 \$ - \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal	(144,531) \$0.00 <u>2009 NPV</u>	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 30,000</u>	0 <u>2010</u> \$238.01 \$ - \$ - \$ -	(153,333) <u>2011</u> \$238.01 \$333,687 \$	0 <u>2012</u> \$238.01 \$ - \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 30,000</u> <u>\$ 30,000</u>	0 <u>2010</u> \$238.01 \$ - \$ - \$ - \$ - \$ -	(153,333) <u>2011</u> \$238.01 \$333,687 \$ 30,000 \$30,000	0 <u>2012</u> \$238.01 \$ - \$ - \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u>	0 <u>2010</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ -	(153,333) <u>2011</u> \$238.01 \$333,687 \$ 30,000 \$30,000 \$ 30,000	0 <u>2012</u> \$238.01 \$ - \$ - \$ - \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687 \$ 28,278	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ - <u>\$ -</u></u>	0 <u>2010</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	(153,333) <u>2011</u> \$238.01 \$333,687 \$ 3 3,687 \$ 3 0,000 \$ 3 0,000 \$ 3 0,000 \$ 3 0,000 \$ 3 0,000	0 <u>2012</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u>	0 <u>2010</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ -	(153,333) <u>2011</u> \$238.01 \$333,687 \$ 30,000 \$30,000 \$ 30,000	0 <u>2012</u> \$238.01 \$ - \$ - \$ - \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687 \$ 28,278	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ - <u>\$ -</u> <u>\$ -</u> <u>\$ -</u></u>	0 <u>2010</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	(153,333) <u>2011</u> <u>\$238.01</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,6000</u> <u>\$333,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$30,0000</u> <u>\$50,0000</u> <u>\$50,0000</u> <u>\$50,0000</u> <u>\$50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,0000</u> <u>50,00000</u> <u>50,00000</u> <u>50,00000</u> <u>50,00000</u> <u>50,000000000000</u>	0 <u>2012</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687 \$ 28,278	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ - <u>\$ -</u></u>	0 <u>2010</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	(153,333) <u>2011</u> \$238.01 \$333,687 \$ 3 3,687 \$ 3 0,000 \$ 3 0,000 \$ 3 0,000 \$ 3 0,000 \$ 3 0,000	0 <u>2012</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
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Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687 \$ 28,278 \$ -	(153,333) - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ - <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ -</u> <u>\$ 166,631</u></u>	0 <u>2010</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	(153,333) <u>2011</u> <u>\$238.01</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$335,687</u> <u>\$335,687</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,757</u> <u>\$355,75755555557 <u>\$3555,7575555555555555555555</u></u>	0 <u>2012</u> \$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687 \$ 28,278 \$ -	(153,333) - - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 333,687</u> <u>\$ 333,687</u> <u>\$ 333,687</u> <u>\$ 333,687</u> <u>\$ - <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ - <u>\$ 5</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 166,631</u> <u>\$ 166,631</u></u></u>	0 <u>2010</u> \$238.01 <u>\$</u> - <u>\$</u> -	(153,333) 2011 \$ 2011 \$ 238.01 \$ 333,687 \$ 333,687 \$ 333,687 \$ 333,687 \$ 333,687 \$ 333,000 \$ 333,687 \$ 333,000 \$ 333,687 \$ 333,000 \$ 333,000 \$ 30,000 \$ 50,000 \$ 50,0000 \$ 50,0000 \$ 50,000	0 <u>2012</u> \$238.01 <u>\$</u> - \$ \$ - \$ \$ - <u>\$</u> -	Other Utility Billed capacity impact Other Utility Billed capacity impact
Alternate Energy Impact (Increase) (kWh) Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Partney Program Costs Incremental Cost Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases)	(144,531) \$0.00 <u>2009 NPV</u> \$ 333,687 \$ 28,278 \$ -	(153,333) - - <u>\$ Total</u> <u>\$ 333,687</u> <u>\$ 333,687</u> <u>\$ 333,687</u> <u>\$ 333,687</u> <u>\$ 333,687</u> <u>\$ 5 <u>5</u> 30,000 <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 30,000</u> <u>\$ 166,631</u> <u>\$ 166,631</u> <u>\$ 166,631</u> <u>\$ 166,631</u></u>	0 <u>2010</u> \$238.01 <u>\$</u> - <u>\$</u> - <u>5</u> - - <u>\$</u> - <u>5</u> - - <u>5</u> - - - <u>5</u> - - - - - - - - - - - - - -	(153,333) <u>2011</u> <u>\$238.01</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$333,687</u> <u>\$336,0000</u> <u>\$333,687</u> <u>\$336,0000</u> <u>\$335,677</u> <u>\$355,677</u> <u>\$355,677</u> <u>\$355,677</u> <u>\$355,677</u> <u>\$355,677</u> <u>\$355,677</u> <u>\$355,677</u> <u>\$356,6631</u> <u>\$366,631</u> <u>\$356,673,746</u> <u>\$356,673,746</u>	0 <u>2012</u> \$238.01 <u>\$</u> - \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	Other Utility Billed capacity impact Other Utility Billed capacity impact
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								F	ROGRAM								ALTER	RNATE				NET	F PRESENT V	ALUE							BENEFIT/CO	ST								PARAMET	rers				
						co	ISTS (\$000)							SAVINGS (GJ))	LIFE	Imp	pact	Levelized Cost	Utility Benefi	ts (Costs)	Participa	nt Benefits (Costs)	Progr	am Net Savi	ings			Participant						UTIL	ITY					PARTICIPA	INT		
			Utility			Partners										Years	Energy	Capacity	(\$/GJ)	Program J	Alternate F	Program C	arbon Tax	Alternate Na		Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternate Supply			Carbon E		Natu	tural Gas Tariff Ene	rgy Tariff Capacity Tariff
		Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWb	kW		(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	(\$'000s)	(\$'000s)		Rate Impact	Total Resource	(\$'000s)		\$/GJ		\$/kWh		\$/GJ	\$/GJ	S/kWh S	\$/kW/a \$	\$/GJ \$	5/kWh \$/kW/a
	Lab	el B	c	D	E	F	6	н	1	1	к	L	м	N	0	Р	Q	R	s	т	U	v	w	x	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AI	AK	AL	AM	AN	AO	AP	AQ	AR	AS AT
	Source Sheet or Calculatio	n Program	Program	8+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	н/і	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M × N × AN	M×N×AD	i x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	Input	Program	Input	Input	Input	PV(AM,P,- inputD25)	Input In	PV(AM,P,- PV InputD28) Inp	V(AM,P,- nputD29)	Input	Input Input
Schools	2011																																												
Geo	bexchange - Elementary	0	30	30	0	0	0	167	197	15%	0%	85%	1,011	100%	1,011	20	(153)	-	3	113	(193)	106	16	(133)	10,587	(1,606)	-	3.8	167	(11)	(0.1)	0.8	(0.2)	(276)	7.15%	111.84	7%	1.26	7.2%	104.71	15.79	0.87	0.00	9.999	0.083
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A B C D E F G H I J K L M N O P Q	Q R S T U V W X Y Z AA AB AC AD AE AF AG AH AI
1 UTILITY Fortis BC	
Z S	
4 Year 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 20	2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041
6 NATURAL GAS 7 Incremental Cost of Gas (nominal) \$ Per GJ \$5.50 \$ 6.17 \$ 6.81 \$ 7.35 \$ 7.87 \$ 88.26 \$ 88.79 \$ 9.19 \$ 9.40 \$ 99.81 \$ 100	510.05 510.25 510.47 510.70 510.99 511.17 511.42 511.67 511.92 512.19 512.45 512.73 513.01 513.29 513.58 513.88 514.19 514.50 514.83
8 1 Year 0 1 2 3 4 5 6 7 8 9 10 11 12 13	
9 carbon tax \$ per GJ 0.75 1.00 1.25 1.50 1.50 1.50 1.50 1.50 1.50 1.50 1.5	1.50 1.50 1.50 1.50 1.50 1.50 1.50 1.50
10 Distribution adder Sper GJ 0.16 </th <th></th>	
11 Total incremental cost of gas including carbon 6.41 7.32 8.21 9.01 9.52 9.92 10.22 10.43 10.64 10.85 11.05 11.26 11.47 11.68 12 2 GDP Deflator 1.00	1.68 11.90 12.13 12.35 12.59 12.83 13.07 13.32 13.58 13.44 14.11 14.38 14.66 14.95 15.24 15.54 15.84 16.15 16.31 1.00 </th
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14 Net Present Value -2010 \$12.36 \$19.03 \$25.87 \$33.61 \$39.16 \$45.47 \$51.47 \$57.19 \$62.63 \$67.80 \$72.71 \$77.39 \$81	<u>\$81.83</u> <u>\$86.05</u> <u>\$90.07</u> <u>\$93.89</u> <u>\$97.52</u> <u>\$100.98</u> <u>\$104.26</u> <u>\$107.39</u> <u>\$110.36</u> <u>\$113.19</u> <u>\$115.88</u> <u>\$118.43</u> <u>\$120.87</u> <u>\$123.18</u> <u>\$125.39</u> <u>\$127.49</u> <u>\$129.48</u> <u>\$131.38</u> <u>\$133.17</u>
15 Net Present Value -2011 \$13.99 \$21.31 \$28.54 \$35.56 \$42.31 \$48.75 \$54.87 \$60.70 \$66.24 \$71.51 \$76.51 \$81 16 6 Net Present Value -2012 \$13.51 \$23.25 \$30.78 \$38.01 \$44.91 \$51.47 \$57.71 \$63.65 \$69.29 \$74.66 \$79	\$81.27 \$85.80 \$90.10 \$94.20 \$98.90 \$101.79 \$105.31 \$108.66 \$111.84 \$114.87 \$117.75 \$120.49 \$127.95 \$120.99 \$121.91 \$123.33 \$134.37 \$15.65 \$79.76 \$85.80 \$90.10 \$97.27 \$10.74 \$105.51 \$111.51 \$111.88 \$121.79 \$124.85 \$127.77 \$122.16 \$138.47 \$136.65 \$138.76
10 0 ret Present value-2012 53:0 \$25:25 \$30.78 \$38.01 \$44.91 \$51.47 \$57.71 \$30.55 \$692.9 \$44.60 \$79	\$/9./b \$84.61 \$89.22 \$99.501 \$91.7.8 \$100.51 \$109.10 \$112.51 \$113.76 \$118.85 \$121.74 \$129.77 \$153.18 \$154.47
1 carbon tas \$prc(3) 0.79 1.79 <th1.79< th=""> 1.79</th1.79<>	
20 Incremental Cost of Elec S Pr kWh S0.12 Image: Second s	
21 incremental Cost on E Capacity SPErKWa S17000	
26 Reidential Retail Reidential Retail Reidential Retail Customers 799,928 Total Customers in BC 80,000 ford Residential and Commercial Customers on VI Image: Customers	
Critical Control Action Control Action <t< th=""><th></th></t<>	
29 TGVI S Per MJ \$0.0143 72	
30 Electricity S Per MJ \$0.0230 511 151145 Teach BCH Contenent BC 500 500 500 500 500 500 500 500 500 50	
31 Electricity S per kWh \$0.0827 1.511 1.511,435 Total BCH Residential Customers in BC 89% 32 Electricity S per kW per year Image: Control of the second secon	
33 Commercial Retail Image: Commercial Retail	
34 TGI \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	
35 TGVI \$ Per MJ \$ 0.0169 8 6 6 6 6 6 6 7 6 7 <th7< th=""> <th7< th=""> <th7< th="" th7<=""></th7<></th7<></th7<>	
Construction Construction<	
38 Electricity S per kW per year \$52,000 15 <th></th>	
40 [AX]	2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2049 2044
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43 2 Carbon \$ Pertonne \$ 20.00 \$ \$ 25.00 \$ \$ 30.00 \$ \$ \$ 30.00 \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	<u>\$30.00</u> <u>80</u> <u>80</u> <u>80</u> <u>80</u> <u>80</u> <u>80</u> <u>80</u> <u></u>
44 3 Carbon \$PerGJ \$\$0.9976 \$1.4964 <th>\$1.4964 <t< th=""></t<></th>	\$1.4964 \$1.4964 <t< th=""></t<>
46 5 Carbon (Real) 51.0 51.25 51.50	1.00 1.00 1.00 1.00 1.00 1.00 1.00 1.00
47 6 Net Present Value -2010 \$2.02 \$3.23 \$4.37 \$5.43 \$6.42 \$7.34 \$8.20 \$9.00 \$9.75 \$10.45 \$11.11 \$11	\$11.72 \$12.29 \$12.82 \$13.31 \$13.78 \$14.21 \$14.61 \$14.99 \$15.34 \$15.67 \$15.99 \$16.26 \$16.52 \$16.77 \$17.00 \$17.22 \$17.42 \$17.41 \$17.75 \$17.76 \$1
	\$11.56 \$12.77 \$12.74 \$13.27 \$13.27 \$14.23 \$14.66 \$15.64 \$15.79 \$16.12 \$16.42 \$16.71 \$16.72 \$17.45 \$17.67 \$17.87 \$18.00
49 8 NetPresent Value-2012 8 27.0 53.02 55.05 56.11 57.00 58.08 59.69 51.04	\$11.14 \$11.79 \$12.40 \$12.97 \$13.50 \$14.46 \$14.89 \$15.29 \$15.67 \$16.02 \$16.35 \$16.64 \$17.21 \$17.45 \$17.69 \$17.00 \$18.10
51 Discoutt Rate (real) ¹	
52 <u>TERASEN GAS</u>	
53 Rato of Inflation 1.90%	
34 (Gi 7.15%) 55 Tevi 7.15%	
56 <u>BCHYDRO</u>	
57 Rate of Inflation 2.00% Image: Constraint of the image: Constraintof the image: Constrainto of the image: Constraint of	
58 BC Hydro 7.15% 59 Customer 7.15%	
D3 Customer 1.1.3% Image: Constant Co	
61	
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64 64 65 66 66 67 68 68 66 67 68 68 66 67 68 68 68 68 68 66<	

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Schools NEW									
Measure Data for Geoexc	hange -	Fler	mentary						
Wiedsure Bata for Geoexe	nunge	LICI	nentary						
PER MEASURE				Utility Incentive to the participant	partner incentive				
Incremental Cost	\$ 166	5,631							
Total Incentive		-							
Participant	\$ 166	5,631							
Annual Impact Per Measure									
Energy Savings per installation	1011		GJ		Average Annnual Energy	Savings per Mea	sure		
Free Rider Rate / Net-to-Gross			1.00		Net-to-Gross				
Alternate Energy Impact	-552	2	GJ	-153,333	kWh				
Alternate Capacity Impact			kW/a						
Measure Lifetime	20		Years	Estimated lifespan of m	neasure				
ANNUAL ACTIVITY	<u>2010 N</u>	NPV	Total	2010	2011	201	12	Explanatory Notes	
Number of Installations									
		1	1	0	1			Estimated Participatation	
Impact									
Gross Energy Savings (GJ)		944	1,011	0	1,011	0		Extension of Unit Savings x No. of Upgrades	
Net Energy Savings (GJ)		944	1,011	0	1,011	0		Gross Energy Savings less Free Riders	
Alternate Energy Impact (Increase) (kWh)	(14	3,102)	(153,333)	0	(153,333)	0		Other Utility Billed energy impact	
Alternate Capacity Impact (Increase) (kW/a)		\$0.00	-					Other Utility Billed capacity impact	
Benefit Cost Summary	<u>2010 N</u>	NPV	<u>\$ Total</u>	<u>2010</u>	<u>2011</u>	<u>201</u>	12]	
Avoided Revenue Requirements									
PV \$ per GJ				\$107.39			\$115.76		
Energy Purchases	\$ 13	13,072	\$ 113,072	<u>\$</u>	\$ 113,0	72 \$	-	_	
Utility Program Costs									
DSM Incentives			\$-	\$-	\$	\$	-		
Administration			\$ 30,000	<u>\$</u> -	<u>\$</u> 30,0	00			
Subtotal	\$ 2	7,998	\$ 30,000	\$ -	\$ 30,0	00 \$	-		
Partner Program Costs	1				,			-	
DSM Incentives			\$-	\$-	\$	\$	-		
Administration			\$ -	\$ -	\$	- \$	-		
Subtotal	Ś	-	<u>s</u> -	\$ -		Ś	-		
Participants' Net Costs	7		Ŧ	Ŧ	Ŧ	Ŷ		-	
Incremental Cost			\$ 166,631	s -	\$ 166,6	31 \$	-		
	Ś 15	E E 1 3							
Subtotal Alternate Savings - Net	ə 15	5,512	\$ 166,631	ş -	ə 166,t	31 \$	-	-	
•			\$ (192,678)	ć	\$ (192,6	79) ¢		\$1.257 PV \$ per kWh	
	1		\$ (192,678)			78)\$. \$	-	\$1.257 PV \$ per kWn PV\$ per kW/a	
Energy (Purchases)			ć			S			
Capacity (Purchases)			<u>\$</u> -	<u>\$</u>		<u>+</u>			
Capacity (Purchases) Subtotal		92,678)	<u>+</u>	<u>.</u>	\$ (192,6	78) \$	-	_	oto plue Altornati- C
		92,678) 63,116) 18.6	<u>+</u>	<u>.</u>	\$ (192,6 \$ (276,7	<u>+</u>		Avoided Revenue Requirement less Utility less Partners less Participant Co	osts plus Alternate Sav

RTIS BC								PR	OGRAM								ALTER	INATE				N	NET PRESENT	VALUE							BENEFIT/COST									PARAN	METERS				
w Initiative Programs - Geoexchange Secondary SCT						COSTS (S	6000)							SAVINGS (G	I)	LIFE	Imp	act	Levelized Cost	Utility Bene	rfits (Costs)	Partici	pant Benefit	s (Costs)	Pro	ogram Net S	avings			Participant						UTIL	.ITY					PARTIC	IPANT		
FEI		Utility			Partn	ners										Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Ga	s Alternate Energy		Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternate Supply	Discount Rate	Natural Gas NPV	Carbon Tax NPV	Alternate Energy NPV	Alternate Capacity NPV	Natural Gas Tariff	nergy Tariff
	Incentives	Administration	Total	Incentives	Administ	tration	fotal	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWh	kW		(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MWb)	(kW)	Utility	(\$'000s)	(\$'000s)	1	ate Impact	SCT	(\$'000s)		\$/GJ		\$/kWh		\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/6J	\$/kWh
Label	в	c	D	E	F		G	н		1	к	L	м	N	0	Р	Q	R	s	т	U	v	w	×	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AI	AK	AL	AM	AN	AO	AP	AQ	AR	AS
Source Sheet or Calculation	Program	Program	B+C	Program	Progra	am	E+F	Program	D+G+H	D/I	G/I	н/і	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AD	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*	N) PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	Input	Program	Input	Input	Input	PV(AM,P,- InputD25)	Input	PV(AM,P,- inputD28)	PV(AM,P,- InputD29)	Input	Input
2011 SIDENTIAL: Geoexchange - Secondary	0	30	30	c)	0	0	524	554	5%	0%	95%	6,223	1009	6,223	20	(419)		0	1,925	(973)	926	139	(516)) 92,583	6,23	6) -	64.2	2 524	549	1.0	2.0	1.7	398	3.00%	238.01	3%	1.79	3.0%	148.76	22.35	1.23	0.00	9.999	0.083

	D	<u> </u>		-	_	0			<u> </u>	× I			N	0	D	0	D	<u> </u>	T		V	14/	V	V	7		AD	40			A.C.	10	A11	
1 UTILITY	В	FORTIS BC	D	E	F	G	Н	I	J	К	L	М	N	0	Р	Q	R	5		U	V	W	Х	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
		FURIISBU																																
2 3 4 5 6 7 8 1 9 10 11 12 2 13 3 14 4 15 5 16 6 17 18 19 20 21 22 23 24 25 RETAIL 26 RETAIL 22 23 30 31 32 33 34 35 36 37 38 39 40 TAX	1	I	I I	1	1	1	1		I I	1			1	1	1	1	1	1	1	1	1	1	I	1	1	1	1	1	I.	1	1	I.	1	
4	Ι	Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5		Units																																
6	NATURAL GAS																																	
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28		\$15.28	\$15.28	0.00120	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28
8 1	carbon tax	Year \$ per GJ	0.00	0.00	2	3	4 0.00	5	6 0.00	7	8	9	10 0.00	11 0.00	12	13	14	15	16 0.00		18	19 0.00		21	22	23 0.00	24	25	26	27	28	29 0.00	30 0.00	31
10	Distribution adder	\$ per GJ	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.16	0.16	0.16	0.00			0.16			0.00	0.16	0.16	0.00	0.00	0.00	0.16	0.00	0.16	0.00
11	Total incremental cost of gas including c		15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44		15.44	15.44		15.44 1:					15.44		15.44	15.44	15.44	15.44	15.44		15.44	15.28
12 2	GDP Deflator		1.00	1.00	1.00		1.00	1.00		1.00	1.00		1.00				1.00	1.00		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00
13 3	Incremental Cost of Gas (Real) Net Present Value -2010		\$15.44	\$15.44 \$29.54	\$15.44 \$43.67	\$15.44 \$57.39	\$15.44 \$70.71	\$15.44 \$83.64		\$15.44 \$108.38	\$15.44 \$120.22		\$15.44 \$142.86	\$15.44 \$153.69	\$15.44 \$164.20	\$15.44 \$174.41	\$15.44 \$184.32	\$15.44 \$193.94	\$15.44 \$203.28	\$15.44 \$212.35	\$15.44 \$221.16	\$15.44 \$229.71	\$15.44 \$238.01	\$15.44 \$246.07	\$15.44 \$253.89	\$15.44 \$261.48	\$15.44 \$268.86	\$15.44 \$276.02	\$15.44 \$282.97	\$15.44 \$289.72	\$15.44 \$296.27	\$15.44 \$302.63	\$15.44 \$308.81	\$15.28 \$314.74
15 5	Net Present Value -2010			329.34	\$43.67		\$57.39	\$83.04		\$96.20	\$120.22		\$142.80	\$133.69	\$153.69	\$164.20	\$184.32	\$193.94	\$193.94	\$203.28	\$212.35	\$229.71	\$229.71	\$238.01	\$233.89	\$253.89	\$261.48	\$268.86		\$289.72	\$290.27 \$289.72	\$296.27	\$302.63	\$308.74
16 6	Net Present Value -2012					\$29.54	\$43.67	\$57.39		\$83.64	\$96.20		\$120.22	\$131.71	\$142.86		\$164.20	\$174.41	\$184.32		\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07	\$253.89	\$261.48		\$276.02	\$282.97	\$289.72	\$296.27	\$302.56
17																																		
18	ELECTRICITY	_																																
20	Incremental Cost of Elec	S Per kWh	\$0.12																															
21	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00																															
22																																		
23	1																																	
25 RETAIL	I																																	
26 KETAIL			Rate	Customers		789.928	Total Customers in	n BC	80.000 Tot	al Residential an	d Commercial C	ustomers on VI																						
27	Residential Retail			000's																														
28		GI \$ Per MJ	\$0.0100	640		712,304	Total Residential C	Customers in BC																										
29		VI \$ Per MJ	\$0.0143 \$0.0230	72																														
31	Electrici	ty \$ Per MJ	\$0.0230	1.511		1 511 435	Total BCH Resider	ntial Customers i	n BC		80%																							
32		y \$perkWperyear	00.0027	1,011		1,0111,000	rour Derriceauer	and contrast	DC .		0776																							
33	Commercial Retail																																	
34		GI \$ Per MJ	\$0.0094 \$0.0169	78		77,624	Total Commercial	Customers in BC																										
35	TG Electrici	VI \$ Per MJ	\$0.0169	8																														
37		y \$ per kWh	\$0.0769	190		189,764	Total Light Industri	ial and Commerc	cial Customers in BC																									
38	Electrici	y \$ per kW per year	\$52.0000	15																														
39	1	-																																
40 TAX		37																																
41 42 1 43 2		Year	2009	2010 0	2011	2012	2013	2014 4	2015 5	2016 6	2017	2018 8	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029 19	2030 20	2031	2032 22	2033	2034 24	2035 25	2036 26	2037	2038 28	2039 29	30
43 2	Carbon	\$ Per tonne		\$20.00	\$25.00		\$30.00	\$30.00		\$30.00	\$30.00		\$30.00		\$30.00		\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00		\$30.00	\$30.00	\$30.00	\$30.00	\$30.00
44 3	Carbon	\$ Per GJ		\$0.9976	\$1.2470		\$1.4964	\$1.4964		\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964
45 4 46 5	GDP Deflator		┨───┤	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
46 5	Carbon (Real) Net Present Value -2010		+ +	\$1.00	\$1.25 \$2.14	\$1.50 \$3.51	\$1.50 \$4.84	\$1.50	\$1.50 \$7.39	\$1.50 \$8.60	\$1.50 \$9.78		\$1.50 \$12.05	\$1.50 \$13.13	\$1.50 \$14.18	\$1.50 \$15.19	\$1.50 \$16.18	\$1.50 \$17.14	\$1.50 \$18.08	\$1.50 \$18.98	\$1.50 \$19.86	\$1.50 \$20.71	\$1.50 \$21.54	\$1.50 \$22.35	\$1.50 \$23.13	\$1.50 \$23.89	\$1.50 \$24.62	\$1.50 \$25.34	\$1.50 \$26.03	\$1.50 \$26.71	\$1.50 \$27.36	\$1.50 \$27.99	\$1.50 \$28.61	\$1.50 \$29.21
48 7	Net Present Value -2010				92.19	\$2.62	\$3.99	\$5.32	\$6.61	\$7.86	\$9.08		\$11.41	\$12.52	\$13.60	\$13.19	\$15.67	\$16.66	\$17.62	\$18.55	\$19.46	\$20.34	\$21.34	\$22.02	\$22.82	\$23.61	\$24.36	\$25.10	\$25.81	\$26.51	\$27.18	\$27.84	\$28.47	\$29.09
49 8	Net Present Value -2012						\$2.86	\$4.23	\$5.56	\$6.85	\$8.11	\$9.32	\$10.50	\$11.65	\$12.76	\$13.85	\$14.90	\$15.91	\$16.90	\$17.86	\$18.80	\$19.70	\$20.58	\$21.43	\$22.26	\$23.07	\$23.85	\$24.61	\$25.34	\$26.06	\$26.75	\$27.42	\$28.08	\$28.71
50 51	Discount Rate (real) ¹		+																															
52	TERASEN GAS		+ +																															
53	Rate of Inflation	on 1.90%																																
54		GI 3.00%																																
55		VI 3.00%	+																															
57	BC HYDRO Rate of Inflation	on 2.00%	+ +																															
58	BC Hyd																																	
59	Custom	er 3.00%																																
60	Footnote 1: Source LR 0705	31	+																															
62		-	SHEET LABE	LS																														
63 New Construction	n																																	
64	Geoexchange - Secondary		BASEBOARD)																														
65		0	HEATPUMP																															
00			1																															

FORTIS BC			only ente	er in k	ooxes mark	ed in blue	9
Schools							
NEW							
Measure Data for Geoexch	nange - Seco	ndarv					
PER MEASURE			Utility Incentive to the participant	ра	rtner incentive		
			the participant				
Incremental Cost	\$ 524,221						
Total Incentive	¢ 534,334			\$	-		
Participant Annual Impact Per Measure	\$ 524,221						
Energy Savings per installation	6223.0	GJ		Average	e Annnual Energy Savin	zs ner Measure	
Free Rider Rate / Net-to-Gross	0%	1.00		Net-to-		s per measure	
Alternate Energy Impact	-1509	GJ	-419,167	kWh			
Alternate Capacity Impact		kW/a	-, -				
Measure Lifetime	20	Years	Estimated lifespan of r	measure			
ANNUAL ACTIVITY	2009 NPV	То	tal 2010		2011	2012	Explanatory Notes
Number of Installations							<u></u>
	1		1 0		1		Estimated Participatation
Impact							
Gross Energy Savings (GJ)	5,866	6,2	23 0		6,223	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	5,866	6,2	23 0		6,223	0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	(395,105)	(419,1	57) 0		(419,167)	0	Other Utility Billed energy impact
Alternate Capacity Impact (Increase) (kW/a)	\$0.00		-				Other Utility Billed capacity impact
		•					
Benefit Cost Summary							
Benefit Cost Summary	2009 NPV	\$ Total	2010		2011	2012	
Benefit Cost Summary Avoided Revenue Requirements	<u>2009 NPV</u>	<u>\$ Total</u>	2010		2011	2012	
	<u>2009 NPV</u>	<u>\$ Total</u>	<u>2010</u> \$238.0)1	<u>2011</u> \$238.01	<u>2012</u> \$238.02	1
Avoided Revenue Requirements	2009 NPV \$ 1,481,124		\$238.0)1 \$	\$238.01		-
Avoided Revenue Requirements PV \$ per GJ			\$238.0		\$238.01	\$238.01	- 1 -
Avoided Revenue Requirements PV \$ per GJ Energy Purchases			\$238.0		\$238.01 1,481,124	\$238.01	- 1 -
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs		\$ 1,481,1	\$238.0 24 \$ -	\$	\$238.01 1,481,124	\$238.01 \$ -	- 1 -
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration	\$ 1,481,124	\$ 1,481,1 \$ \$ 30,0	\$238.0 24 <u>\$</u>	<u>\$</u> \$	\$238.01 1,481,124 - 30,000	\$238.02 <u>\$</u> - \$-	- 1 -
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal		\$ 1,481,1 \$ \$ 30,0	\$238.0 24 <u>\$ -</u> - \$ - 20 <mark>\$</mark>	\$ \$ - \$	\$238.01 1,481,124 - 30,000	\$238.01 \$ -	
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration	\$ 1,481,124	\$ 1,481,1 \$ \$ 30,0	\$238.0 24 <u>\$</u>	\$ \$ - \$	\$238.01 1,481,124 - - - - 30,000 30,000	\$238.02 <u>\$</u> - \$-	_ 1 _ _
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs	\$ 1,481,124	\$ 1,481,1 \$ <u>\$ 30,0</u> \$ 30,0	\$238.0 24 \$ - - \$ - 00 \$ - 00 \$ -	\$ \$ - \$ \$	\$238.01 1,481,124 - - - - 30,000 30,000	\$238.0: <u>\$</u> \$ \$	
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration	\$ 1,481,124 \$ 28,278	\$ 1,481,1 \$ <u>\$ 30,0</u> \$ 30,0 \$ <u>\$ </u> <u>\$ -</u>	\$238.0 - \$ - 00 \$ 00 \$ - - \$ - \$	\$ \$ - \$ \$ \$ - \$	\$238.01 1,481,124 - - - - - - - -	\$238.0: \$ - \$ - \$ - \$ - \$ - \$ - \$ -	
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal	\$ 1,481,124 \$ 28,278	\$ 1,481,1 \$ <u>\$ 30,0</u> \$ 30,0 \$ <u>\$ </u> <u>\$ </u>	\$238.0 24 <u>\$</u> - - \$ - 00 <u>\$</u> 00 \$ - - \$ - \$ -	\$ \$ \$ \$ \$	\$238.01 1,481,124 - - - - - - - -	\$238.0: <u>\$</u> - <u>\$</u> - <u>\$</u> - <u>\$</u> -	
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs	\$ 1,481,124 \$ 28,278	\$ 1,481,1 \$ <u>\$ 30,0</u> \$ 30,0 \$ <u>\$ -</u> \$ -	\$238.0 24 \$ - - \$ - 00 \$ - 00 \$ - - \$ - \$ - \$ - \$ - \$ - \$ - \$	\$ \$ \$ \$ - \$ \$ \$ \$	\$238.01 1,481,124 - - - - - - - -	\$238.0: \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	- 1 -
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost	\$ 1,481,124 \$ 28,278 \$ -	\$ 1,481,1 \$ <u>\$ 30,0</u> \$ 30,0 \$ <u>\$ -</u> \$ - <u>\$ 524,2</u>	\$238.0 24 \$ - - \$ - 00 \$ - 00 \$ - - \$ - \$ - \$ - \$ - 21 \$ -	\$ - \$ \$ - \$ - \$ \$ - \$ \$ - \$ - \$	\$238.01 1,481,124 - - - - - - - - - - 524,221	\$238.0: \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal	\$ 1,481,124 \$ 28,278	\$ 1,481,1 \$ <u>\$ 30,0</u> \$ 30,0 \$ <u>\$ -</u> \$ - <u>\$ 524,2</u>	\$238.0 24 \$ - - \$ - 00 \$ - 00 \$ - - \$ - \$ - \$ - \$ - 21 \$ -	\$ \$ \$ \$ - \$ \$ \$ \$	\$238.01 1,481,124 - - - - - - - -	\$238.0: \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net	\$ 1,481,124 \$ 28,278 \$ -	<u>\$ 1,481,1</u> <u>\$ 30,0</u> <u>\$ 30,0</u> <u>\$ 30,0</u> <u>\$ 5</u> <u>\$ -5</u> <u>\$ 524,2</u> <u>\$ 524,2</u>	\$238.0 \$238.0 \$238.0 \$238.0 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - - \$ - - \$ - - \$ - - - - - - - - - - - - -	<u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u>	\$238.01 1,481,124 - - - - - - - - - - - - - - - - - - -	\$238.0: \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	- - -
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases)	\$ 1,481,124 \$ 28,278 \$ -	<u>\$ 1,481,1</u> <u>\$ 30,0</u> <u>\$ 30,0</u> <u>\$ 30,0</u> <u>\$ 5</u> <u>\$ 524,2</u> <u>\$ 524,2</u> <u>\$ 524,2</u> <u>\$ 524,2</u> <u>\$ 524,2</u> <u>\$ 524,2</u>	\$238.0 \$250.0 \$250.0	<u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u>	\$238.01 1,481,124 - - - - - - - - - - - - - - - - - - -	\$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases) Capacity (Purchases)	\$ 1,481,124 \$ 28,278 \$ - \$ 494,129	<u>\$ 1,481,1</u> <u>\$ 30,0</u> <u>\$ 30,0</u> <u>\$ 30,0</u> <u>\$ 5</u> <u>\$ -</u> <u>\$ 524,2</u> <u>\$ 524,2</u> <u>5 524,2 <u>5 524,2</u> <u>5 524,2 <u>5 524,2</u> <u>5 524,2</u> <u>5 524,2</u> <u>5 524,2</u> <u>5 524,2</u> <u>5 524,2</u> <u>5 524,2 <u>5 524,2</u> <u>5 524,2</u> <u>5 524,2 <u>5 524,2</u> <u>5 524,2 <u>5 524,2</u> <u>5 524,2 <u>5 524,2 <u>5 524,2</u> <u>5 524,2 <u>5 524,2 <u>5 524,2</u> <u>5 524,2 <u>5 524,2 <u>5 524,2</u> <u>5 524,2 <u>5 524,2</u> <u>5 5</u></u></u></u></u></u></u></u></u></u></u></u></u></u></u></u></u>	\$238.0 \$24 \$ - - \$ - 00 \$ - - \$ - - \$ - - \$ - \$ - \$ 20 \$ - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - -	<u>-</u> <u>-</u> <u>-</u> <u>-</u> <u>-</u> <u>-</u> <u>-</u> <u>-</u> <u>-</u> <u>-</u>	\$238.01 1,481,124 - - - - - - - - - - - - - - - - - - -	\$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	- - -
Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases)	\$ 1,481,124 \$ 28,278 \$ -	\$ 1,481,1 \$ 30,0 \$ 30,0 \$ 30,0 \$ 5 \$ - \$ 5 \$ - \$ 524,2 \$ 524,2 \$ 524,2 \$ (748,3) \$ - \$ (748,3)	\$238.0 \$24 \$ - - \$ - 00 \$ - - \$ - - \$ - - \$ - \$ - \$ 20 \$ - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - - \$ - -	<u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u> <u>\$</u>	\$238.01 1,481,124 - - - - - - - - - - - - - - - - - - -	\$238.01 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	

Fortis BC																		1																n											
New Initiative Programs - Geoexchange Secondary TRC					0	OSTS (\$000)		PROGRAM					SAVINGS (GJ)		LIFE	ALTE		Levelized Cost	Utility Be	nefits (Costs)		NET PRESENT		Prog	ram Net Sa	vings			Participant	BENEFIT/COS	T				υτιμ	TY			PARAME	TERS	PARTICIP	JPANT			
		Utility			Partners										Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Discount	Alternate Supply			Carbon		Course the D		Energy Tariff	Capacity Tariff
	Incentives	Administration	Total	Incentives	Administration	Total	Participa	nt Total	% Utilit	y % Partne	r % Participan	t Gross	Net-to-Gross	Net		MWh	kW		(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	(\$'000s)	(\$'000s)		Rate Impact	Total Resource	(\$'000s)	Rate	\$/GJ		\$/kWh		\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/GJ	\$/kWh	\$/kW/a
Label	в	c	D	E	F	6	н		L	к	L	м	N	0	Р	Q	R	s	т	U	v	w	×	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	6/1	нл	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q×N×AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	Input	Program	Input	Input		PV(AM,P,- InputD25)			PV(AM,P,- InputD29)	Input	Input	Input
2011 <u>Schools</u> Geoexchange -Iscondary	0	30	30	0	c		0 5	24 55	54	5%	95	% 6,223	100%	6,223	20	(419)	-	0	#N/A	N/A	N/A	#N/A	N/A	124,460	(8,383)	-	#N/A	524	#N/A	#N/A	#N/A	#N/A	#N/A	0.00%	#N/A	0%	0.00	0.0%	0.00	#N/A	0.00	0.00	0.000	0.000	-

5 Units Uni	2035 2036 2037 2038 2039 2040 20 301 \$13.29 \$13.38 \$13.88 \$14.19 \$14.50 \$14.30 1.50 1.50 1.50 1.50 1.50 1.50 1.50 1.60 0.16 0.16 0.16 0.16 0.16 1.01 1.00 1.00 1.00 1.00 1.00 1.00 1.00 1.00 1.00 46 \$14.95 \$15.24 \$15.54 \$15.54 \$16.15 \$16.5
2 3 4 5 2	3.01 \$13.29 \$13.58 \$13.88 \$14.19 \$14.50 \$14.50 2.6 2.7 2.8 2.9 3.0 3.1 1.50 1.50 1.50 1.50 1.50 1.50 0.16 0.16 0.16 0.16 0.16 0.16 1.495 15.24 15.54 15.84 16.15 16.31 1.00 1.00 1.00 1.00 1.00 1.00 1.00 46 514.95 \$15.24 515.4 \$16.15 \$16.15 \$16.15
A Vear 200 201 201 201 201 201 201 202 202 202 202 202 202 202 202 202 202 202 202 202 202 202 202 203	3.01 \$13.29 \$13.58 \$13.88 \$14.19 \$14.50 \$14.50 2.6 2.7 2.8 2.9 3.0 3.1 1.50 1.50 1.50 1.50 1.50 1.50 0.16 0.16 0.16 0.16 0.16 0.16 1.495 15.24 15.54 15.84 16.15 16.31 1.00 1.00 1.00 1.00 1.00 1.00 1.00 46 514.95 \$15.24 515.4 \$16.15 \$16.15 \$16.15
A Vear 200 201 201 201 201 201 201 202 202 202 202 202 202 202 202 202 202 202 202 202 203	3.01 \$13.29 \$13.58 \$13.88 \$14.19 \$14.50 \$14.50 2.6 2.7 2.8 2.9 3.0 3.1 1.50 1.50 1.50 1.50 1.50 1.50 0.16 0.16 0.16 0.16 0.16 0.16 1.495 15.24 15.54 15.84 16.15 16.31 1.00 1.00 1.00 1.00 1.00 1.00 1.00 46 514.95 \$15.24 515.4 \$16.15 \$16.15 \$16.15
Present loss of Gas (nominal) SPer GJ S5.0 S6.1 S6.81 S7.35 S7.87 S8.26 S8.76 S8.76 S8.76 S8.76 S9.76 S9.76 S9.77	3.01 \$13.29 \$13.58 \$13.88 \$14.19 \$14.50 \$14.50 2.6 2.7 2.8 2.9 3.0 3.1 1.50 1.50 1.50 1.50 1.50 1.50 0.16 0.16 0.16 0.16 0.16 0.16 1.495 15.24 15.54 15.84 16.15 16.31 1.00 1.00 1.00 1.00 1.00 1.00 1.00 46 514.95 \$15.24 515.4 \$16.15 \$16.15 \$16.15
Present Number	26 27 28 29 30 31 1.50 1.50 1.50 1.50 1.50 1.50 1.50 0.16 0.16 0.16 0.16 0.16 0.16 1.61 14.95 15.24 15.54 15.84 16.15 16.31 1.00 1.00 1.00 1.00 1.00 1.00 1.00 46 51495 \$15.24 515.4 \$16.15 \$16.15 \$16.15
Incremental Cost of Gas (nominal) S PerGl SS.50 SS.61 SS.78 SS.826 SS.85 SS.89 SS.90 S9.90 S9.90 S9.00	26 27 28 29 30 31 1.50 1.50 1.50 1.50 1.50 1.50 1.50 0.16 0.16 0.16 0.16 0.16 0.16 1.61 14.95 15.24 15.54 15.84 16.15 16.31 1.00 1.00 1.00 1.00 1.00 1.00 1.00 46 51495 \$15.24 515.4 \$16.15 \$16.15 \$16.15
9 carbon tax \$ perGl 0.75 1.00 1.50	1.50 1.50 1.50 1.50 1.50 1.50 0.16 0.16 0.16 0.16 0.16 0.16 14.95 15.24 15.54 15.84 16.15 16.31 1.00 1.00 1.00 1.00 1.00 1.00 1.0 4.66 \$14.95 \$15.24 \$15.54 \$15.54 \$16.15 \$16.15
10 Distribution adder per GI 0.6	0.16 0.16 0.16 0.16 0.16 14.95 15.24 15.54 15.84 16.15 16.31 1.00 1.00 1.00 1.00 1.00 1.20 1.20 4.66 514.95 \$15.54 \$15.54 \$15.54 \$16.15 \$16.31
13 3 Incremental Cost of Gas (Real) 56.4 57.32 58.9 51.25 512.35 512.35 512.35 513.37 513.32 513.35 513.45 514.41 514.38 511.45 511.45 511.45 511.45 512.35 512.35 512.35 513.37 513.32 513.35 513.35 513.34 514.11 514.38 511.45 511.45 511.45 511.25 512.35 512.35 512.35 513.35 513.35 513.35 513.35 513.35 513.35 513.41 514.35 511.45 511.45 511.25 512.35 512.35 512.35 513.	14.95 15.24 15.54 15.84 16.15 16.31 1.00 1.00 1.00 1.00 1.00 1.00 4.66 \$14.95 \$15.24 \$15.54 \$15.84 \$16.15 \$15.94
13 3 Incremental Cost of Gas (Real) 56.4 57.32 58.9 51.25 512.35 512.35 512.35 513.37 513.32 513.35 513.45 514.41 514.38 511.45 511.45 511.45 511.45 512.35 512.35 512.35 513.37 513.32 513.35 513.35 513.34 514.11 514.38 511.45 511.45 511.45 511.25 512.35 512.35 512.35 513.35 513.35 513.35 513.35 513.35 513.35 513.41 514.35 511.45 511.45 511.25 512.35 512.35 512.35 513.	1.00 1.00 1.00 1.00 1.00 1.00 1.00 1.00
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1 1	
Net Present Value -2011 State Stat	
16 6 Net Present Value -2012 \$15.5 \$23.2 \$30.78 \$38.01 \$44.91 \$51.47 \$57.71 \$63.65 \$59.29 \$74.6 \$79.76 \$84.61 \$89.22 \$93.61 \$97.78 \$101.74 \$105.51 \$109.10 \$112.51 \$115.76 \$118.85 \$121.79 \$12	3.10 \$125.59 \$127.95 \$130.19 \$132.33 \$134.37 \$136.
	4.58 \$127.24 \$129.77 \$132.18 \$134.47 \$136.65 \$138.
Incremental Cost of Elec S Per kWh S0.12 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity S Per kWh S170.00 Image: Cost of E Capacity	
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25 RETAIL	
26 Rate Continuers 789 973 Total Continuers in BC 80.000 Total Residential and Commercial Continuers on VI	
27 Residential Retail 0000 x 00000 x 0000 x 0000	
29 TGV1 \$ Per MJ \$0.0143 72 Image: Constraint of the second se	
OD EBRURGY STREAD 3002-0 Fill (1) Stread (2) Stread (2) <tread (2)<="" th=""></tread>	
33 Commercial Retail	
34 TGI SP.or MJ \$0.0094 77.624 Total Commercial Customers in BC Image: Commercial Cus	
35 TGV1 S Per MJ \$0.0169 8 Image: Second	
36 Electricity S Per MJ \$0.0214 Image: Mail and Commercial Customers in BC Ima	
S1 Lieutricity Spectral 340000 190 190.16 100.100 100.000 100.	
39	
40 TAX	
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42 1 Vear 0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24	25 26 27 28 29 30
43 2 Carbon \$Pertonne \$20.00 \$25.00 \$30.00 \$	0.00 \$30.00 \$30.00 \$30.00 \$30.00 \$30.00 \$30.00
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51 Discut Rate (real) ¹ Discut Rate (real) ²	
53 Rate of Inflation 1.90% Image: Constraint of the state of	
24 6 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7	
57 Rate of Inflation 2.0%	
58 BC Hydro 7.15%	
59 Customer 7.15% C C C C C C C C C C C C C C C C C C C	
60 Footnote 1: Source LR 070531	

Utility Levelized Cost per GJ (Lifetime)

4.5

\$

\$

only enter in boxes marked in blue

Fortis BC			only ente	er in boxes mark	ed in blue	e
Schools						
NEW						
Measure Data for Geoexcl	hange - Se	condarv				
PER MEASURE			Utility Incentive to	partner incentive		
			the participant			
Incremental Cost	\$ 524,22	1				
Total Incentive		-				
Participant	\$ 524,22	1				
Annual Impact Per Measure						
Energy Savings per installation	6223.0	GJ		Average Annnual Energy Savi	ngs per Measure	
Free Rider Rate / Net-to-Gross	0%	1.00		Net-to-Gross		
Alternate Energy Impact	-1509	GJ	-419,167	kWh		
Alternate Capacity Impact		kW/a				
Measure Lifetime	20	Years	Estimated lifespan of n	neasure		
ANNUAL ACTIVITY	2010 NPV	Tota	l 2010	2011	2012	Explanatory Notes
Number of Installations		1000				
		1	1 0	1		Estimated Participatation
Impact			· · ·	-		Estimated For departation
Gross Energy Savings (GJ)	6,22	3 6,223	0	6,223	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	6,22			6,223	0	Gross Energy Savings Less Free Riders
Alternate Energy Impact (Increase) (kWh)	(419,16			(419,167)	0	Other Utility Billed energy impact
			, 0	(419,107)	0	
Alternate Capacity Impact (Increase) (kW/a)	\$0.0	-	-			Other Utility Billed capacity impact
Benefit Cost Summary						
Benefit Cost Summary	2010 NDV	Ć Tatal	2010	2014	2042	
Avaided Devenue Desvinements	2010 NPV	<u>\$ Total</u>	<u>2010</u>	2011	<u>2012</u>	<u> </u>
Avoided Revenue Requirements						
PV \$ per GJ			#N/A	#N/A	#N/A	
Energy Purchases	#N/A	#N/A	#N/A	#N/A	#N/A	=
Utility Program Costs						
DSM Incentives		\$ -	\$ -	\$-	\$-	
Administration		\$ 30,000	<u>\$</u>	- \$ 30,000		
Subtotal	\$ 30,00	0 \$ 30,000	· \$ -	\$ 30,000	\$ -	
Partner Program Costs						_
DSM Incentives		s -	- \$ -	\$ -	\$ -	
Administration		\$ -	\$.	- \$ -	\$	
	ć		-	\$ -	-	-
Subtotal	\$ -	\$ -	\$ -	ې -	\$ -	_
Participants' Net Costs			¢.		¢.	
Incremental Cost		<u>\$ 524,221</u>		\$ 524,221	<u>\$</u> -	-
Subtotal	\$ 524,22	1 \$ 524,221	. \$ -	\$ 524,221	\$-	_
Alternate Savings - Net						
Energy (Purchases)		\$ -	- \$ -	\$-	\$-	\$0.000 PV \$ per kWh
Capacity (Purchases)		<u>\$</u> -	\$-	\$-	\$-	PV\$ per kW/a
Subtotal	\$ -	\$ -	\$ -	<u>\$</u>	Ś -	—
Total Resource Net Benefit (Cost)	• #N/А	1	#N/A	#N/A	#N/A	Avoided Revenue Requirement less Utility less Partners less Participant Costs plus A
		-	*		*	

\$

4.5 \$

- Informational (for comparison with supply options)

RTIS BC									PROG	RAM								ALTERNATE					N	ET PRESENT	VALUE							BENEFIT/CO	ST								PARA	METERS					_
w Initiative Programs - Solar Resid	idential SCT						COSTS (\$000)						s	AVINGS (GJ)		LIFE	Impact		Cost U	tility Benef	its (Costs)	Particip	ant Benefits	(Costs)	Pro	ogram Net S	avings			Participant						U	TILITY					PART	ICIPANT			
FEI	-		Utility			Partners	5									,	fears	Energy Cap	pacity	(\$/GJ) P	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity			Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternation Supply	e Discount Rate	Natural Gas NPV	Carbon Tax NPV	Energy	Alternate Capacity NPV		Energy Tarif	ff Capaci Tarif
		Incentives	Administration	Total	Incentives	Administrati	ion Total	Part	rticipant	Total %	Utility % i	artner % P	Participant	Gross	Net-to-Gross	Net		MWh I	w	((\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MWb)	(kW)	Utility	(\$'000s)	(\$'000s)		Rate Impact	SCT	(\$'000s)		\$/GJ		\$/kWh		\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/GJ	\$/kWh	\$/kW
	Label	в	с	D	E	F	G		н	1	1	к	L	м	N	0	Р	Q	R	s	т	U	v	w	×	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
Sou	ource Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Pro	rogram	D+G+H	D/I	s/i	н/1	Program	Program	VisiN Pi	rogram	Program Pro	mang	D/Y	OxAJ	Q×N×AL	M x N x AN	M x N x AD	N x (QxAP + RxAQ)	PV(AJ,P,-O)	PV(AK,P,-Q*1	4) PV(AK,P,-R)	T/D	H>0, (V+W)<	H<0, (V+W)>0, X	AD/AC	T/{V+D}	(T+U)/I	(T+U)-I	Input	Program	Input	Input	Input	PV(AM,P,- InputD25)	Input	PV(AM,P,- InputD28)	PV(AM,P,- InputD29)	Input	Input	Inpu
2011 SIDENTIAL: Res Solar		0	1	1	0		0	0	8	8	8%	0%	92%	12	100%	12	25	0	-	3	4	N/A	2	0	N/A	209	() .	- 6.	98	2	0.3	1.6	0.5	. (4	4) 3.00%	276.02	2 3%	6 2.05	3.0%	174.11	26.0	3 1.44	L 0.00	9.999	0.083	
	Total Residential	0	1	1	0		0	0	8	8	8%		92%	12		12		0	0	3	4	N/A	2	0	N/A	209	N//	N/0	6	9 8	2	03	16	0.5	6	1) 0.7	(3	3)									

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		FOR HS BC																																
2	1	1	т т	1	1	1	1	1	I I	1	1	ı ı	1	1	1	1	1	1	1	I	1	1	1	1	1	1	1	1	1	1	I.	1	1	
4	I	Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5		Units																																
6	NATURAL GAS																																	
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28		\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28
8 1		Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16		18	19	20	21	22	23	24	25	26	27	28	29	30	31
9	carbon tax Distribution adder	\$ per GJ \$ per GJ	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16		0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00							
10	Total incremental cost of gas including car		15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44			15.44	15.44		15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.44	15.28
12 2	GDP Deflator	<u></u>	1.00	1.00	1.00		1.00	1.00		1.00	1.00		1.00	1.00	1.00		1.00	1.00		1.00	1.00		1.00	1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00
13 3	Incremental Cost of Gas (Real)		\$15.44	\$15.44	\$15.44		\$15.44	\$15.44		\$15.44	\$15.44		\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44		\$15.44	\$15.44		\$15.44	\$15.44		\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.28
14 4	Net Present Value -2010			\$29.54			\$70.71	\$83.64		\$108.38	\$120.22		\$142.86	\$153.69	\$164.20		\$184.32	\$193.94		\$212.35	\$221.16		\$238.01	\$246.07		\$261.48	\$268.86	\$276.02		\$289.72	\$296.27	\$302.63	\$308.81	\$314.74
15 5	Net Present Value -2011	-			\$29.54	\$43.67 \$29.54	\$57.39 \$43.67	\$70.71 \$57.39		\$96.20 \$83.64	\$108.38 \$96.20	0.0000	\$131.71 \$120.22	\$142.86	\$153.69 \$142.86	\$164.20 \$153.69	\$174.41 \$164.20	\$184.32 \$174.41	\$193.94 \$184.32	\$203.28 \$193.94	\$212.35 \$203.28	\$221.16 \$212.35	\$229.71 \$221.16	\$238.01 \$229.71	\$246.07 \$238.01	\$253.89 \$246.07	\$261.48 \$253.89	\$268.86 \$261.48		\$282.97 \$276.02	\$289.72 \$282.97	\$296.27 \$289.72	\$302.63 \$296.27	\$308.74 \$302.56
10 0	Net Present Value -2012					\$29.54	\$43.67	\$57.39	\$70.71	\$85.04	\$96.20	\$108.38	\$120.22	\$131./1	\$142.80	\$153.09	\$164.20	\$1/4.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$258.01	\$246.07	\$253.89	\$261.48	\$208.80	\$276.02	\$282.97	\$289.72	\$296.27	\$302.56
18																																		
19	ELECTRICITY																																	
20	Incremental Cost of Elec	\$ Per kWh	\$0.12																															
21	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00																															
22																																		
2 3 4 5 6 7 8 1 9 10 11 12 2 13 3 14 4 15 5 16 6 17 18 19 20 11 14 14 14 15 5 16 6 17 18 19 20 21 22 23 34 22 23 34 22 23 33 34 35 36 37 38 39 40 TAX			+ +																															
25 RETAIL																																		
26			Rate	Customers		789,928	Total Customers in	BC	80,000 Tot	al Residential and	d Commercial C	Customers on VI																						
27	Residential Retail			000's																														
28		GI \$ Per MJ	\$0.0100	640		712,304	Total Residential Cu	istomers in BC																										
29	TGV		\$0.0143 \$0.0230	72																														
31		y \$ Per MJ y \$ per kWh	\$0.0230	1.511		1.511.425	Total PCU Pacidant	tial Customars in	PC		9000																							
32		SperkWing \$perkWing \$	00.0027	1,211		1,011,000	I Otal DCIT Resident	tial Customers in	i be		0.7 /0																							
33	Commercial Retail																																	
34		GI \$ Per MJ	\$0.0094	78		77,624	Total Commercial C	Customers in BC																										
35	TGV		\$0.0169 \$0.0214	8																														
37		y \$ Per MJ y \$ per kWh	\$0.0214	190		190 764 7	Total Light Industrie	al and Command	ial Customers in RC																									
38		\$ per kW per year	\$52.0000	15		109,704	i otar Eight industria	ar and Commerci	tai Custoniers în DC																									
39																																		
40 TAX																																		
41 42 1 43 2		Year	2009		2011	2012	2013	2014		2016	2017	2018	2019	2020	2021	2022	2023	2024		2026	2027		2029	2030		2032	2033	2034		2036	2037	2038	2039	2040
42 1		Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
43 2 44 3	Carbon Carbon	\$ Per tonne \$ Per GJ		\$20.00 \$0.9976	\$25.00 \$1.2470		\$30.00 \$1.4964	\$30.00 \$1.4964		\$30.00 \$1.4964	\$30.00 \$1.4964		\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00 \$1.4964		\$30.00 \$1.4964	\$30.00 \$1.4964		\$30.00 \$1.4964	\$30.00 \$1.4964		\$30.00 \$1.4964	\$30.00 \$1.4964		\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00 \$1.4964		\$30.00	\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00 \$1.4964	\$30.00 \$1.4964
44 5	GDP Deflator	3 ret GJ	+ +	\$0.9976	\$1.2470	31.4904	\$1.4964 1.00	\$1.4964		\$1.4964	\$1.4964	0111701	\$1.4964	\$1.4964	\$1.4964	\$1.4964	31.4904	\$1.4964 1.00	\$1.4964	\$1.4964	\$1.4964	51.4964	\$1.4964 1.00	\$1.4964	\$1.4964	\$1.4964	\$1.4964	51.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	51.4964	\$1.4904 1.00
46 5	Carbon (Real)			\$1.00	\$1.25	\$1.50	\$1.50	\$1.50		\$1.50	\$1.50		\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50		\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50
47 6	Net Present Value -2010				\$2.14	\$3.51	\$4.84	\$6.13	\$7.39	\$8.60	\$9.78		\$12.05	\$13.13	\$14.18	\$15.19	\$16.18	\$17.14	\$18.08	\$18.98	\$19.86	\$20.71	\$21.54	\$22.35	\$23.13	\$23.89	\$24.62	\$25.34		\$26.71	\$27.36	\$27.99	\$28.61	\$29.21
48 7 49 8	Net Present Value -2011		+ +			\$2.62	\$3.99	\$5.32 \$4.23	\$6.61	\$7.86 \$6.85	\$9.08 \$8.11	0.0000	\$11.41 \$10.50	\$12.52	\$13.60 \$12.76	\$14.65	\$15.67 \$14.90	\$16.66	\$17.62	\$18.55 \$17.86	\$19.46	\$20.34 \$19.70	\$21.19 \$20.58	\$22.02 \$21.43	\$22.82 \$22.26	\$23.61 \$23.07	\$24.36 \$23.85	\$25.10 \$24.61	\$25.81 \$25.34	\$26.51 \$26.06	\$27.18 \$26.75	\$27.84 \$27.42	\$28.47 \$28.08	\$29.09
49 8 50	Net Present Value -2012	+	+ +				\$2.86	\$4.23	\$5.56	\$6.85	\$8.11	\$9.32	\$10.50	\$11.65	\$12.76	\$13.85	\$14.90	\$15.91	\$16.90	\$17.86	\$18.80	\$19.70	\$20.58	\$21.43	\$22.26	\$23.07	\$23.85	\$24.61	\$25.34	\$26.06	\$26.75	\$27.42	\$28.08	\$28.71
51	Discount Rate (real) ¹	1	+ +																															
52	TERASEN GAS																																	
53	Rate of Inflatio																																	
54			+ +																															
56	TGV BC HYDRO	3.00%	+ +																															
57	Rate of Inflatio	n 2.00%	+ +																															
58	BC Hydr	o 3.00%																																
59	Custome	ar 3.00%																																
60	Footnote 1: Source LR 07053	1	+ +																															
62			SHEET LABE																															
63 New Constructio	n	-																																
64	Res Solar		BASEBOARD	D																														
65		0	HEATPUMP																															
66								_		-				-																				-

FORTIS BC
RESIDENTIAL

NEW										
Measure Data for Res Sola	n									
Medsare Bata for Res Sole										
PER MEASURE					Utility Incentive to)	partner incentive			
FER MEASURE					the participant		partner incentive			
Incremental Cost	Ś	7,500								
Total Incentive		7,500				Ś	-			
Participant		7,500								
Annual Impact Per Measure										
Energy Savings per installation		12.0	GJ			Av	verage Annnual Energy Savi	ngs per	r Measure	
Free Rider Rate / Net-to-Gross		0%	1.00			Ne	et-to-Gross			
Alternate Energy Impact			GJ		0	kV	Wh			
Alternate Capacity Impact			kW/a							
Measure Lifetime		25	Years		Estimated lifespan of	measu	ure			
ANNUAL ACTIVITY	200	09 NPV	Т	otal	2010		2011		2012	Explanatory Notes
Number of Installations			-							
		1		1	0		1			Estimated Participatation
Impact	1			-			_	1		· · · · · · · · · · · · · · · · · · ·
Gross Energy Savings (GJ)		11		12	0		12		0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)		11		12	0		12		0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)		0		0	0		0		0	Other Utility Billed energy impact
Alternate Capacity Impact (Increase) (kW/a)		\$0.00		-	0		0		U	Other Utility Billed capacity impact
Benefit Cost Summary										
benefit cost Summary	200		ć Tatal		2010		2014		2012	
Avoided Revenue Requirements	200	09 NPV	<u>\$ Total</u>		2010		2011		2012	
•					¢276	~~	ć		6276.02	
PV \$ per GJ			ć a	242	\$276.0		\$276.02		\$276.02	
Energy Purchases	\$	3,312	\$ 3,3	312	<u>\$</u>	\$	3,312	\$	-	
Utility Program Costs			1.							
DSM Incentives			\$		\$-	\$		\$	-	
Administration			-	625	\$	<u>- \$</u>	625			
Subtotal	\$	589	\$ 6	625	\$-	\$	625	\$	-	
Partner Program Costs										-
DSM Incentives			\$	-	\$-	\$	-	\$	-	
Administration			\$	-	\$	- \$	-	\$	-	
Subtotal	\$	-	Ś	-	\$ -	\$	-	\$	-	
Participants' Net Costs	7		7		Ŧ	Ŷ		Ŷ		
Incremental Cost			Ś 7.5	500	\$ -	Ś	7,500	\$	_	
	<u>,</u>	7.000	<u>, , , , , , , , , , , , , , , , , , , </u>			— ÷				
Subtotal	\$	7,069	\$ 7,5	500	\$ -	\$	7,500	Ş	-	
Alternate Savings - Net	1				ć	~		ċ		
5 (5)				-	\$-	\$	-	\$	-	\$2.090 PV \$ per kWh
Energy (Purchases)			\$							
Capacity (Purchases)			\$		<u>\$</u>	\$		\$	-	PV\$ per kW/a
Capacity (Purchases) Subtotal	\$		\$ \$		<u>\$</u> - \$-	\$	-	\$	-	PV\$ per kW/a
Capacity (Purchases)	\$ \$ \$	- (4,346) 38.9	\$ \$		<u>\$</u>	\$	- (4,813)	\$ \$	-	

Fortis BC																																													
							P	ROGRAM								ALTER	NATE					NET PRESENT V	ALUE						BE	NEFIT/COS	ज								PARAM	AETERS					
New Initiative Programs - Solar Residential TRC					cc	OSTS (\$000)							SAVINGS (GJ)		LIFE	Imp	act	Levelized Cost	Utility Ben	nefits (Costs)	Partici	pant Benefits	Costs)	Proj	gram Net Sav	vings		F	Participant						UT	TUTY					PARTICIPA	NT			
		Utility			Partners										Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs T	otal Benefits B	lenefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternate Supply		Natural Gas NPV	Carbon		Natu	atural Gas Tariff Ener	nergy Tariff	Capacity Tariff
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWh	kW		(\$'000s)	(\$'000s)	(\$*000s)	(\$'000s)	(\$*000s)	(GJ)	(MWh)	(kW)	Utility	(\$'000s)	(\$'000s)		Rate Impact	Total Resource	(\$'000s)		\$/GJ		\$/kWh		\$/GJ	\$/GJ	\$/kWh \$	5/kW/a \$	\$/GJ \$	\$/kWh \$	\$/kW/a
Label	в	c	D	E	F	6	н	1	L	к	L	м	N	0	P	Q	R	s	т	U	v	w	x	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	нл	Program	Program	MxN	Program	Program	Program	D/Y	0xAJ	Q×N×AL	M x N x AN	M x N x AD	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H⊲0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	Input	Program	Input	Input	Input	PV(AM,P,- inputD25)	Input	PV(AM,P,- PV InputD28) Inp	(AM,P,- putD29)	Input I	Input	Input
2011 RESIDENTIAL:																																													
Solar Residential Hot Water Pilot Program	0	1	1	0	0	(8	8	89	6 0%	92%	12	100%	12	25	0	-	5	2	N/A	2	0	N/A	138	-	-	2.4	8	2	0.2	0.7	0.2	(7	7) 7.15%	125.59	6%	1.53	6.0%	127.82	17.22	1.06	0.00	9.999	0.083	-
																																					1								

	P	6	D	E I	E	G	Н		J	к		М	N	0	Р	Q	R	\$	- T	U	V	w	х	Y	7	AA	AB	AC	AD	AE	AF	AG	AH	AI
1 UTILITY	D	Fortis BC	U	E	F	6	п	I	J	ĸ	L	IVI	IN	0	F	Q	К	3		U	v	vv	^		Z	AA	AD	AC	AD	AE	AF	AG	АП	AI
		Torus De																																
3			1					J		1	J		1	1		1				1				1	1	1	1	1		1				
4		Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5	NATURAL GAS	Units																																
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$5.50	\$6.17	\$6.81	\$7.35	\$7.87	\$8.26	\$8.56	\$8.78	\$8.99	\$9.19	\$9.40	\$9.60	\$9.81	\$10.03	\$10.25	\$10.47	\$10.70	\$10.93	\$11.17	\$11.42	\$11.67	\$11.92	\$12.19	\$12.45	\$12.73	\$13.01	\$13.29	\$13.58	\$13.88	\$14.19	\$14.50	\$14.82
8 1	· ·	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16		18	19	20	21	22	23	24	25	26	27	28	29	30	31
9	carbon tax	\$ per GJ	0.75	1.00	1.25	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50		1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
11	Distribution adder Total incremental cost of gas including c	\$ per GJ arbon	0.16 6.41	0.16 7.32	0.16 8.21	0.16 9.01	0.16 9.52	0.16 9.92	0.16 10.22	0.16 10.43	0.16 10.64	0.16 10.85	0.16 11.05	0.16 11.26	0.16 11.47	0.16 11.68	0.16 11.90	0.16 12.13		0.16 12.59	0.16	0.16 13.07		0.16 13.58	0.16 13.84	0.16 14.11	0.16 14.38	0.16 14.66	0.16 14.95	0.16 15.24	0.16 15.54	0.16 15.84	0.16 16.15	16.31
12 2	GDP Deflator		1.00	1.00			1.00	1.00		1.00	1.00		1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13 3	Incremental Cost of Gas (Real)		\$6.41	\$7.32			\$9.52	\$9.92		\$10.43	\$10.64	\$10.00	\$11.05			\$11.68	\$11.90	\$12.13	\$12.35	\$12.59	\$12.83	\$13.07	\$13.32	\$13.58	\$13.84	\$14.11	\$14.38	\$14.66	\$14.95	\$15.24	\$15.54	\$15.84	\$16.15	\$16.31
14 4	Net Present Value -2010 Net Present Value -2011			\$12.36	\$19.03 \$13.99		\$32.61 \$28.54	\$39.16 \$35.56		\$51.47 \$48.75	\$57.19 \$54.87		\$67.80 \$66.24	\$72.71 \$71.51	\$77.39 \$76.51		\$86.05 \$85.80	\$90.07 \$90.10	\$93.89 \$94.20	\$97.52 \$98.09	\$100.98 \$101.79	\$104.26 \$105.31	\$107.39 \$108.66	\$110.36 \$111.84	\$113.19 \$114.87	\$115.88 \$117.75	\$118.43 \$120.49	\$120.87 \$123.10	\$123.18 \$125.59	\$125.39 \$127.95	\$127.49 \$130.19	\$129.48 \$132.33	\$131.38 \$134.37	\$133.17 \$136.28
16 6	Net Present Value -2012				<i>Q13.77</i>	\$15.51	\$23.25	\$30.78		\$44.91	\$51.47		\$63.65	\$69.29	\$74.66		\$84.61	\$89.22	\$93.61	\$97.78	\$101.74	\$105.51	\$109.10	\$112.51	\$115.76	\$118.85	\$121.79	\$124.58		\$129.77	\$132.18	\$134.47	\$136.65	\$138.70
17																																		
18	ELECTRICITY	-																																
2 3 4 5 6 7 8 1 9 9 10 11 12 2 13 3 14 4 4 4 4 15 5 16 6 17 17 18 19 20 21 22 23 24 25 RETAIL 22 23 24 25 RETAIL 27 28 29 30 30 31 33 34 35 36 37 38 39 39 39 30 37 38 39 39 39 30 30 31 30 31 31 31 31 31 31 31 31 31 31	Incremental Cost of Elec	\$ Per kWh	\$0.12																															
21	Incremental Cost of E Capacity		\$170.00																															
22																																		
23	T																																	
25 RETAIL	I																																	
26			Rate	Customers		789,928	Fotal Customers in	n BC	80,000 To	tal Residential and	d Commercial C	lustomers on VI																						
27	Residential Retail		60.0100	000's																														
28		GI \$ Per MJ VI \$ Per MJ	\$0.0100 \$0.0143	640 72		712,304	Fotal Residential C	Customers in BC																										
30	Electrici		00.0115	12																														
31		y \$ per kWh	\$0.0827	1,511		1,511,435	Fotal BCH Resider	ntial Customers in	n BC		89%																							
32	Electrici Commercial Retail	y \$ per kW per year																																
34		GI § Per MJ	\$0.0094	78		77.624	Fotal Commercial	Customers in BC																										
35		VI \$ Per MJ	\$0.0169	8																														
36		y \$ Per MJ	\$0.0214	100																														
37		y \$ per kWh y \$ per kW per year	\$0.0707	190		189,764	Fotal Light Industr	ial and Commerc	cial Customers in BC																									
39		• <u>• • • • • • • • • • • • • • • • •</u>																																
40 TAX																																		
41 42 1		Year	2009	2010	2011	2012	2013	2014		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
42 1 43 2	Carbon	Year \$ Per tonne		0 \$20.00	1 \$25.00	2 \$30.00	3	4 \$30.00	5 \$30.00	6 \$30.00	7 \$30.00	8 \$30.00	9 \$30.00	10 \$30.00	11 \$30.00	12 \$30.00	13 \$30.00	14 \$30.00	15 \$30.00	16 \$30.00	\$30.00	18	19 \$30.00	20 \$30.00	21 \$30.00	\$30.00	23 \$30.00	24 \$30.00	25 \$30.00	26 \$30.00	\$30.00	28 \$30.00	29 \$30.00	30 \$30.00
44 3	Carbon	\$ Per GJ		\$0.9976	\$1.2470		\$1.4964	\$1.4964		\$1.4964	\$1.4964		\$1.4964	\$1.4964			\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964
45 4	GDP Deflator			1.00	1.00	1.0.0	1.00	1.00		1.00	1.00						1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
46 5 47 6	Carbon (Real) Net Present Value -2010			\$1.00	\$1.25	\$1.50 \$3.23	\$1.50 \$4.37	\$1.50 \$5.43		\$1.50 \$7.34	\$1.50 \$8.20		\$1.50 \$9.75	\$1.50 \$10.45	\$1.50 \$11.11	\$1.50 \$11.72	\$1.50	\$1.50 \$12.82	\$1.50 \$13.31	\$1.50 \$13.78	\$1.50 \$14.21	\$1.50	\$1.50 \$14.99	\$1.50 \$15.34	\$1.50 \$15.67	\$1.50 \$15.97	\$1.50 \$16.26	\$1.50 \$16.52	\$1.50 \$16.77	\$1.50 \$17.00	\$1.50 \$17.22	\$1.50 \$17.42	\$1.50 \$17.61	\$1.50 \$17.79
48 7	Net Present Value -2010				32.02	\$2.47	\$3.68	\$4.82		\$6.87	\$7.79		\$9.45	\$10.43	\$10.90	+	\$12.29	\$12.82	\$13.31	\$13.76	\$14.21	\$14.61	\$15.06	\$15.44	\$15.87	\$15.97	\$16.42	\$16.52	\$16.97	\$17.00	\$17.45	\$17.67	\$17.87	\$17.79
49 8	Net Present Value -2012						\$2.70	\$3.92	\$5.05	\$6.11	\$7.10	\$8.02	\$8.88	\$9.69	\$10.44	\$11.14	\$11.79	\$12.40	\$12.97	\$13.50	\$14.00	\$14.46	\$14.89	\$15.29	\$15.67	\$16.02	\$16.35	\$16.65	\$16.94	\$17.21	\$17.45	\$17.69	\$17.90	\$18.10
50	Discount Rate (real) ¹																																	
52	TERASEN GAS																																	
53	Rate of Inflati																																	
54	Т	GI 7.15% VI 6.89%	+			├																												
56	BC HYDRO	0.0970	+ +																															
57	Rate of Inflati																																	
58	BC Hyd																																	
59	Footnote 1: Source LR 0705																																	
61	rounde r. source ER 0/03		+ +																															
62																																		
63																																		
65		+																																
66																																		

only enter in boxes marked in blue

12

0

Gross Energy Savings less Free Riders

Fortis BC RESIDENTIAL

RESIDENTIAL						
NEW						
Measure Data for Solar Re	sidential H	lot Water Pilo	t Program			
Medsure Butta for Solar He	Slacificari		t i ogium			
PER MEASURE			Utility Incentive to the participant	partner incentive		
Incremental Cost	\$ 7,500	1				
Total Incentive	\$-					
Participant	\$ 7,500				-	
Annual Impact Per Measure						
Energy Savings per installation	12.0	GJ		Average Annnual Energy Savir	ngs per Measure	
Free Rider Rate / Net-to-Gross	0%	1.00		Net-to-Gross		
Alternate Energy Impact		GJ	0	kWh		
Alternate Capacity Impact		kW/a				
Measure Lifetime	25	Years	Estimated lifespan of me	easure		
ANNUAL ACTIVITY	2010 NPV	Total	2010	2011	2012	Explanatory Notes
Number of Installations						
	:	1	0	1		Estimated Participatation
Impact						· · ·
• Gross Energy Savings (GJ)	1:	12	0	12	0	Extension of Unit Savings x No. of Upgrades

0

12

11

Net Energy Savings (GJ)

Her Energy Sarrings (GS)					Ũ			0	cross Energy surfligs less free finders
Alternate Energy Impact (Increase) (kWh)		0		0	0		0	0	Other Utility Billed energy impact
Alternate Capacity Impact (Increase) (kW/a)		\$0.00		-					Other Utility Billed capacity impact
Benefit Cost Summary									
	20	10 NPV	\$ Tot	al	2010		2011	2012	
Avoided Revenue Requirements									-
PV \$ per GJ					\$120.8	7	\$125.59	\$129.77	
Energy Purchases	\$	1,507	\$	1,507	\$-	\$	1,507	\$ -	
Utility Program Costs									-
DSM Incentives			\$	- 5	\$-	\$	-	\$ -	
Administration			\$	625	\$ -	\$	625		
Subtotal	\$	583	\$	625	\$-	\$	625	\$ -	
Partner Program Costs									
DSM Incentives			\$	- 5	\$-	\$	-	\$ -	
Administration			\$		\$ -	\$	-	\$ -	
Subtotal	\$	-	\$		\$-	\$	-	\$ -	
Participants' Net Costs									-
Incremental Cost			\$	7,500	\$-	\$	7,500	\$ -	
Subtotal	\$	7,000	\$	7,500	\$-	\$	7,500	\$ -	
Alternate Savings - Net								 	
Energy (Purchases)			\$	- 9	\$-	\$	-	\$ -	\$1.534 PV \$ per kWh
Capacity (Purchases)			\$		\$ -	\$	-	\$ -	PV\$ per kW/a
Subtotal	\$	-	\$	- 5	\$-	\$	-	\$ -	_
Total Resource Net Benefit (Cost)	\$	(6,076)		ç	\$ -	\$	(6,618)	\$ -	Avoided Revenue Requirement less Utility less Partners less Participant Costs plus Alternate Savi
Utility Levelized Cost per GJ (Lifetime)	\$	58.9			\$ -	\$	58.9	\$ -	Informational (for comparison with supply options)

ORTIS BC									PROGRAM							ALTER	RNATE				N	NET PRESENT	VALUE						В	ENEFIT/COST								PARA	AMETERS				
ew Initiative Program - Fur	nace Scrap it Program SCT						COSTS (\$000)						:	AVINGS (GJ)	LIFE	Imp	oact	Levelized Cost	Utility Ben	fits (Costs)	Partici	ipant Benefit	s (Costs)	Pro	ogram Net Sa	ivings			Participant						UTILITY					PAR	ICIPANT		
FE	EI		Utility			Partners									Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	 Natural Gas 	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits		atural Gas	TRO Ber	nefits Disc	Utility	atural Altern Gas Discor apply Rat	unt Sun		nt Natural Gas NPV	Carbon / Tax NP	n Energy	Alternate Capacity NPV		Energy Tariff
		Incentives	Administration	Total	Incentives	Administratio	n Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross Net		MWh	kW		(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	(\$'000s)	(\$'000s)	Rab	e Impact S	ст (\$'(000s)		\$/6J	\$/k	Wh	\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/GJ	\$/kWh
	Labe	в	c	D	E	F	G	н	1.1		к	L	м	N O	Р	Q	R	s	т	U	v	w	×	Y	z	AA	AB	AC	AD	AE	AF A	us a	AH A	AJ	AJ AK	A	AM	AN	AD	AP	AQ	AR	AS
	Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	н/1	Program	Program MxN	Program	Program	Program	D/Y	OxAl	Q x N x AL	M x N x AN	M x N x AD	N x (QxAP + RxAQ)	* PV(AI,P,-O)	PV(AK,P,-Q*N	} PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC T	/(V+D) (T+	U)/I (T4	+U)-I Ing	put Pr	ogram Inpu	t Inp	ut Input	PV(AM,P,- InputD25)) Input	PV(AM,P, InputD28)	PV(AM,P,- InputD29)	Input	Input
20: <u>ISIDENTIAL:</u> Scrap It	11	0	0	0	0		0		1 4	4%	0%	96%	9	100%	9 18	1	-	1	2	2	1	0	1	119	13	-	15.3	4	2	0.7	1.8	1.2	1 3.0	00%	221.16	3%	1.65 3.0%	137.5	i2 20.	71 1.1	4 0.00	9.999	0.083
	Total Residential	0	0	0	0		0	n .	1 4	4%	-	96%	9		9	1	0	1	2	2	1	0	1	119	13	N/A	15.3	4	2	0.7	1.8	12	1	15	2								

	P	<u> </u>		-		0				V.			N	0	D 1	0	D	<u> </u>	Ŧ		V	14/	×	V	7			40		A.E.	A.C.	40	A11	
1 UTILITY	В	C FORTIS BC	D	E	F	G	Н	I	J	К	L	М	N	0	Р	Q	R	S	I	U	V	W	Х	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	Al
		FORTISBU																																
2	1	1	т т	1			1	1	1	1	1	ı ı	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	I.	1	1	
4	I	Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5		Units	1																															
6	NATURAL GAS																																	
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28		\$15.28	\$15.28		\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28
8 1		Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16		18	19	20	21	22	23	24	25	26	27	28	29	30	31
10	carbon tax Distribution adder	\$ per GJ \$ per GJ	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16		0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00 0.16	0.00							
11	Total incremental cost of gas including car		15.44	0.10	0.10	0.16	15.44	0.10		0.16	0.10 15.44	0.16	0.16	0.10	0.10	0.10	15.44	0.10			0.10	0.10		0.10	0.10	15.44	15.44	15.44	15.44	15.44	15.44	15.44	0.10	15.28
12 2	GDP Deflator		1.00	1.00			1.00	1.00		1.00	1.00		1.00	1.00	1.00		1.00	1.00		1.00	1.00		1.00	1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00
13 3	Incremental Cost of Gas (Real)		\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44		\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.28
14 4	Net Present Value -2010			\$29.54			\$70.71	\$83.64		\$108.38	\$120.22		\$142.86		\$164.20		\$184.32	\$193.94		\$212.35	\$221.16		\$238.01	\$246.07		\$261.48	\$268.86	\$276.02		\$289.72	\$296.27	\$302.63	\$308.81	\$314.74
15 5	Net Present Value -2011				\$29.54	\$43.67 \$29.54	\$57.39 \$43.67	\$70.71 \$57.39	\$83.64 \$70.71	\$96.20 \$83.64	\$108.38 \$96.20	0.0000	\$131.71 \$120.22	\$142.86 \$131.71	\$153.69 \$142.86	\$164.20 \$153.69	\$174.41 \$164.20	\$184.32 \$174.41	\$193.94 \$184.32	\$203.28 \$193.94	\$212.35 \$203.28	\$221.16 \$212.35	\$229.71 \$221.16	\$238.01 \$229.71	\$246.07 \$238.01	\$253.89 \$246.07	\$261.48 \$253.89	\$268.86 \$261.48		\$282.97 \$276.02	\$289.72 \$282.97	\$296.27 \$289.72	\$302.63 \$296.27	\$308.74 \$302.56
17	Net Present Value -2012		+ +			\$29.54	\$43.67	\$57.39	\$70.71	\$83.64	\$96.20	\$108.38	\$120.22	\$131.71	\$142.86	\$153.69	\$164.20	\$174.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07	\$253.89	\$261.48	\$268.86	\$276.02	\$282.97	\$289.72	\$296.27	\$302.56
18																																		
19	ELECTRICITY																																	-
20	Incremental Cost of Elec	\$ Per kWh	\$0.12										_																					
21	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00																															
22			+ +																															
2 3 4 5 6 7 8 1 9 9 10 11 12 2 3 3 4 4 4 5 5 16 6 17 18 19 20 21 22 23 23 24 25 RETAIL 26 27 28 29 30 31 3 4 4 4 5 5 5 5 5 5 5 5 5 5 5 5 5	1		+ +																	<u> </u>														
25 RETAIL	I																																	
26		-	Rate	Customers		789.928	Total Customers in I	BC	80.000 Tota	al Residential and	d Commercial C	Sustomers on VI																						
27	Residential Retail			000's																														
28		SI \$ Per MJ	\$0.0100	640		712,304	Total Residential Cu	istomers in BC																										
29	TGV		\$0.0143	72																														
30	Electricity	\$ Per MJ \$ per kWh	\$0.0230 \$0.0827	1.511		1.511.405		1.4	20		000																							
32		\$ per kW per year	00.0027	1,311		1,511,435	I otal BCH Residenti	ial Customers in	BC		89%																							
33	Commercial Retail	per k ii per year																																
34	те	SI \$ Per MJ	\$0.0094	78		77,624	Total Commercial Ci	ustomers in BC																										_
35	TGV		\$0.0169	8																														
36	Electricity	\$ Per MJ \$ per kWh	\$0.0214	100		100.751		1 10																										
38		\$ per kW per year	\$52,0000	190		189,764	I otal Light Industria	and Commerci	al Customers in BC																									
39	,	<u></u>																																
40 TAX																																		
41 42 1 43 2		Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
42 1		Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
43 2 44 3	Carbon	\$ Per tonne		\$20.00			\$30.00	\$30.00		\$30.00	\$30.00				\$30.00		\$30.00	\$30.00		\$30.00	\$30.00		\$30.00	\$30.00		\$30.00	\$30.00	\$30.00		\$30.00	\$30.00	\$30.00	\$30.00	\$30.00
44 3	Carbon GDP Deflator	\$ Per GJ	+ +	\$0.9976	\$1.2470	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964
46 5	Carbon (Real)		1 1	\$1.00	1.00	\$1.50	\$1.50	\$1.50		\$1.50	\$1.50		\$1.50	1.00	\$1.50	1.00	\$1.50	\$1.50	1.00	\$1.50	\$1.50		\$1.50	\$1.50	1.00	\$1.50	\$1.50	\$1.50	1.00	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50
47 6	Net Present Value -2010				\$2.14	\$3.51	\$4.84	\$6.13	\$7.39	\$8.60	\$9.78		\$12.05	\$13.13	\$14.18	\$15.19	\$16.18	\$17.14	\$18.08	\$18.98	\$19.86	\$20.71	\$21.54	\$22.35	\$23.13	\$23.89	\$24.62	\$25.34		\$26.71	\$27.36	\$27.99	\$28.61	\$29.21
48 7 49 8	Net Present Value -2011					\$2.62	\$3.99	\$5.32	\$6.61	\$7.86	\$9.08	4.0000	\$11.41	\$12.52	\$13.60	\$14.65	\$15.67	\$16.66	\$17.62	\$18.55	\$19.46	\$20.34	\$21.19	\$22.02	\$22.82	\$23.61	\$24.36	\$25.10	\$25.81	\$26.51	\$27.18	\$27.84	\$28.47	\$29.09
49 8	Net Present Value -2012		+ +				\$2.86	\$4.23	\$5.56	\$6.85	\$8.11	\$9.32	\$10.50	\$11.65	\$12.76	\$13.85	\$14.90	\$15.91	\$16.90	\$17.86	\$18.80	\$19.70	\$20.58	\$21.43	\$22.26	\$23.07	\$23.85	\$24.61	\$25.34	\$26.06	\$26.75	\$27.42	\$28.08	\$28.71
50	Discount Rate (real) ¹	1	+ +																															
52	TERASEN GAS		+ +																															
53	Rate of Inflatio																																	
54	те		+																															
55	TG	/1 3.00%	+ +																															
57	BC HYDRO Rate of Inflatio	n 2.00%	+ +																															
58	BC Hydr		+ +																															
59	Custome	ar 3.00%																																
60	Footnote 1: Source LR 07053																																	
61																																		
62 63 New Constructio	n	+	SHEET LABE	ELS																														
64	Scrap It	-	BASEBOARD	D																														
65	()	0	HEATPUMP	-																														
66																																		

FORTIS BC				only er	nter	in boxes ma	kec	d in blue	
Residential									
NEW									
Measure Data for Scrap It									
PER MEASURE				Utility Incentive	e to	partner incentive			
				the participant		••••••			
Incremental Cost	\$	3,708							
Total Incentive		· · · ·				\$ -			
Participant	\$	3,708							
Annual Impact Per Measure									
Energy Savings per installation		8.6	GJ			Average Annnual Energy S	avings p	per Measure	
Free Rider Rate / Net-to-Gross		0%	1.00			Net-to-Gross			
Alternate Energy Impact		4	GJ	976		kWh			
Alternate Capacity Impact			kW/a						
Measure Lifetime		18	Years	Estimated lifespan	n of me	easure			
ANNUAL ACTIVITY	~	000 NEV/	T	2040		2014		2012	Evaluation / Notoc
	20	009 NPV	Total	2010		<u>2011</u>		2012	Explanatory Notes
Number of Installations		1	1	0		1			Estimated Participatotion
Impact		1	1	U		1			Estimated Participatation
Gross Energy Savings (GJ)		8	9	0		9		0	Extension of Unit Savings x No. of Upgrades
		8	9	0		9		0	
Net Energy Savings (GJ) Alternate Energy Impact (Increase) (kWh)		920	976	0		976		0	Gross Energy Savings less Free Riders Other Utility Billed energy impact
Alternate Capacity Impact (Increase) (kW/a)		\$0.00	970	0		970		0	Other Utility Billed capacity impact
Alternate capacity impact (increase) (kw/a)	I	Ş0.00							
Benefit Cost Summary									
	20	009 NPV	\$ Total	2010		2011		2012	
Avoided Revenue Requirements		<u></u>	<u></u>	2010					-
PV \$ per GJ				\$22	21.16	\$221.	16	\$221.16	
Energy Purchases	\$	1,907	\$ 1,907		-	\$ 1,90		-	
Utility Program Costs									-
DSM Incentives			\$ -	\$	-	\$ -	\$	-	
Administration			\$ 162		-	\$ 16			
Subtotal	\$	153	·	-	-	-	 2\$	_	
Partner Program Costs	Ŷ	102	- 102	Ŷ	-		ڊ ۽	-	-
DSM Incentives			\$ -	\$	-	\$ -	\$	-	
Administration			\$ -	\$			- \$		
Subtotal	Ś	_	<u>,</u> \$-	\$		<u>-</u>			
Participants' Net Costs	Ş	-	- د د	ې	-	- ڊ	Ş	-	-
Incremental Cost			\$ 3,708	\$	-	\$ 3,70	8\$	-	
Subtotal	Ś	3,495		-		-	<u>0 3</u> 8 \$		
Alternate Savings - Net	Ş	3,495	ə 3,708	Ş	-	ə 3,70	ςο	-	-
Energy (Purchases)			\$ 1,611	¢	_	\$ 1,61	1\$		\$1.650 PV \$ per kWh
			\$ 1,611 \$ -	\$ \$	-	\$ 1,61 \$ -		-	PV\$ per kW/a
Capacity (Purchases)	<i>.</i>		·	-		-		-	
Subtotal Total Resource Net Benefit (Cost)	\$ \$	1,611 (129)	\$ 1,611	\$ \$	-	\$ 1,61 \$ (35	1 \$ 2) \$	-	Avoided Revenue Requirement less Utility less Partners less Participan
Utility Levelized Cost per GJ (Lifetime)	\$ \$	(129) 32.6		\$ \$	-		2) Ş .6 Ş		
otinty Levenzed Cost per GJ (Lifetime)	Ş	32.6		Ş	-	ə 32	ζυ	-	Informational (for comparison with supply options)

Fortis BC																																													
							P	ROGRAM								ALTEP	INATE					NET PRESENT	VALUE						BE	NEFIT/COS	r								PARAN	AETERS					
New Initiative Programs - Funace Scrap it program - TRC					co	OSTS (\$000)							SAVINGS (GJ)		LIFE	Imp	act	Levelized Cost	Utility Ber	nefits (Costs) Partici	ipant Benefits	(Costs)	Pro	ram Net Sav	ings		F	Participant						UTI	ШТҮ					PARTICIP	ANT			
		Utility			Partners										Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs T	otal Benefits B	enefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternate Supply	Discount Rate	Natural Gas NPV	Carbon	Alternate A Energy O NPV	Na Na	latural Gas Tariff En	inergy Tariff	Capacity Tariff
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWb	kW		(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	(\$'000s)	(\$'000s)		Rate Impact	Total Resource	(\$'000s)		\$/GJ		\$/kWh		\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/6J	\$/kWh	\$/kW/a
Label	в	c	D	E	F	6	н	1	1	к	L	м	N	0	Р	Q	R	s	т	U	v	w	x	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	нл	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q×N×AL	M x N x AN	M x N x AD	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-i	Input	Program	Input	Input	Input	PV(AM,P,- InputD25)	Input	PV(AM,P,- I InputD28) I	PV(AM,P,- InputD29)	Input	Input	Input
2011 <u>RESIDENTIAL:</u> Scrap It	0	0	0	0	0	0	4	4	49	6 0%	96%	9	100%	9	18	1	-	2	1	1	1	0	1	86	11	-	5.6	4	2	0.5	0.8	0.6	(2)	7.15%	105.31	6%	1.30	6.0%	108.27	15.06	0.90	0.00	9.999	0.083	-

A	B	С	D	E	F	G	Н		J	к		М	N	0	Р	Q	R	S	т	U	V	w	х	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
	D	Fortis BC	D	L		0			J	K	L	IVI		U		Q	K	5	1	0	v	**	~		2	~~	AD	AC	AU		Ai	AG		<u> </u>
2																																		
2 3 4 5 6	1				I							1							1				1		1			1		1		1		
4		Year	2010	2011	2012	2013	3 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5	NATURAL GAS	Units																																
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$5.50	\$6.17	\$6.81	\$7.35	\$7.87	\$8.26	5 \$8,56	\$8,78	\$8.99	\$9.19	\$9.40	\$9.60	\$9.81	\$10.03	\$10.25	\$10.47	\$10.70	\$10.93	\$11.17	\$11.42	\$11.67	\$11.92	\$12.19	\$12.45	\$12.73	\$13.01	\$13.29	\$13.58	\$13.88	\$14.19	\$14.50	\$14.92
7 8 1	incremental cost of Gas (nonlinal)	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	410100	15	0.0110		18	19	20	21	22	23	24	25	26	27	28	<i><i><i>xxxxxxxxxxxxx</i></i></i>	30	314.62
9	carbon tax	\$ per GJ	0.75	1.00	1.25	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50		1.50			1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50		1.50	1.50
0	Distribution adder Total incremental cost of gas including ca	\$ per GJ	0.16 6.41	0.16 7.32	0.16 8.21	0.16 9.01	0.16 9.52	0.16 9.92	0.16 10.22	0.16 10.43	0.16 10.64	0.16 10.85	0.16 11.05	0.16 11.26	0.16 11.47			2.13			0.16 2.83	0.16 13.07		0.16 13.58	0.16 13.84	0.16 14.11	0.16 14.38	0.16 14.66	0.16 14.95	0.16 15.24	0.16 15.54		0.16 16.15	16.31
2 2	GDP Deflator	1001	1.00								1.00			1.00	11.47	1.00	1.00	1.00	12.55	1.00	1.00	1.00	1.00	1.00		14.11	14.55	14.00		1.00	1.00	1.00	1.00	10.51
3 3	Incremental Cost of Gas (Real)		\$6.41		\$8.21				1 1	\$10.43	\$10.64	\$10.85	\$11.05	\$11.26	\$11.47	\$11.68	\$11.90	\$12.13	\$12.35	\$12.59	\$12.83	\$13.07	\$13.32	\$13.58	\$13.84	\$14.11	\$14.38	\$14.66	\$14.95	\$15.24	\$15.54	\$15.84	\$16.15	\$16.31
4 4	Net Present Value -2010 Net Present Value -2011			\$12.36	\$19.03 \$13.99		7 \$32.61 \$28.54			\$51.47 \$48.75	\$57.19 \$54.87	\$62.63 \$60.70	\$67.80 \$66.24	\$72.71 \$71.51	\$77.39 \$76.51	\$81.83 \$81.27	\$86.05 \$85.80	\$90.07 \$90.10	\$93.89 \$94.20	\$97.52 \$98.09	\$100.98 \$101.79	\$104.26 \$105.31	\$107.39 \$108.66	\$110.36 \$111.84		\$115.88 \$117.75	\$118.43 \$120.49	\$120.87 \$123.10		\$125.39 \$127.95	\$127.49 \$130.19	\$129.48 \$132.33	\$131.38 \$134.37	\$133.17 \$136.28
6 6	Net Present Value -2011 Net Present Value -2012				\$15.99	\$21.31 \$15.51	\$28.54				\$54.87			\$69.29	\$74.66	\$79.76	\$85.80	\$90.10	\$94.20		\$101.79	\$105.51	\$108.66	\$111.84			\$120.49	\$123.10		\$127.95	\$130.19	\$132.33	\$134.37 \$136.65	\$136.28
7																																		
8																																		
0 1 1 2 2 3 3 3 4 4 5 5 6 6 7 8 9 9 10 1 12 2 13 3 14 1 15 RETAIL 16 7 17 1 18 9 10 1 14 1 15 RETAIL 16 1 17 1 18 1 19 1 11 1 12 1 13 1 14 1 15 1 16 1 17 1 18 1 19 1 10 1 11 1 12 1 13 1 14 1 15 1 16 1 17 1 18 1 19 1 10 1 10 </th <th>ELECTRICITY Incremental Cost of Elec</th> <th>§ Per kWh</th> <th>\$0.12</th> <th></th> <th></th> <th></th> <th> </th> <th></th>	ELECTRICITY Incremental Cost of Elec	§ Per kWh	\$0.12																															
?1	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00																															
22																																		
23	1																																	
5 RETAIL	I	L																																
26			Rate	Customers		789,928	B Total Customers	in BC	80,000	Total Residential an	nd Commercial C	ustomers on VI																						
27	Residential Retail			000's																														
28		SI \$ Per MJ	\$0.0100 \$0.0143	640		712,304	Total Residential	Customers in BC																										
<u>.9</u>		y \$ Per MJ		12																														
31	Electricit	y \$ per kWh	\$0.0827	1,511		1,511,435	Total BCH Resid	ential Customers in	in BC		89%																							
2	Electricit Commercial Retail	y\$ per kW per year																																
34		SI \$ Per MJ	\$0.0094	78		77.624	Total Commercia	l Customers in BC																										
5		/I \$ Per MJ	\$0.0169	8																														
6		y \$ Per MJ	\$0.0214	100																														
57 18		y \$ per kWh y \$ per kW per year	\$0.0707	190		189,764	Total Light Indus	trial and Commerc	cial Customers in B	С																								
19																																		
0 TAX																																		
1		Year	2009		2011	2012				2016	2017			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030		2032	2033	2034	2035	2036	2037	2038	2039	2040
3 2	Carbon	Year \$ Per tonne		0 \$20.00	1 \$25.00	2	3 \$30.00	4 \$30.00	5 \$30.00	6 \$30.00	7 \$30.00	8 \$30.00	9 \$30.00	10 \$30.00	11 \$30.00	12 \$30.00	\$30.00	14 \$30.00	15 \$30.00	16 \$30.00	\$30.00	18 \$30.00	19 \$30.00	\$30.00	21 \$30.00	\$30.00	\$30.00	24 \$30.00	25 \$30.00	26 \$30.00	\$30.00	28 \$30.00	29 \$30.00	30 \$30.00
4 3	Carbon	\$ Per GJ		\$0.9976	\$1.2470			\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964			\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964
11 12 13 13 13 14 15 14 15 14 15 14 15 14 15 14 15 14 15 14 15 14 15 14 15 14 15 14 15 14 15 15 15 15 15 15 15 15 15 15	GDP Deflator Carbon (Real)			1.00			0 1.00			1.00	1.00 \$1.50			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00 \$1.50	1.00	1.00		1.00	1.00	1.00 \$1.50		1.00	1.00	1.00	1.00	1.00
6 7 6	Carbon (Real) Net Present Value -2010	+		\$1.00	\$1.25 \$2.02	\$1.50 \$3.23	5 \$1.50 \$ \$4.37	\$1.50		\$1.50 \$7.34	\$1.50 \$8.20	\$1.50 \$9.00	\$1.50 \$9.75	\$1.50 \$10.45	\$1.50	\$1.50	\$1.50 \$12.29	\$1.50 \$12.82	\$1.50 \$13.31	\$1.50 \$13.78	\$1.50 \$14.21	\$1.50 \$14.61	\$1.50 \$14.99	\$1.50 \$15.34	\$1.50 \$15.67	\$1.50 \$15.97	\$1.50 \$16.26	\$1.50 \$16.52	\$1.50 \$16.77	\$1.50 \$17.00	\$1.50 \$17.22	\$1.50 \$17.42	\$1.50 \$17.61	\$1.50 \$17.79
8 7	Net Present Value -2011					\$2.47	\$3.68	\$4.82	\$5.88	\$6.87	\$7.79	\$8.65	\$9.45	\$10.20	\$10.90	\$11.56	\$12.17	\$12.74	\$13.27	\$13.76	\$14.23	\$14.66	\$15.06	\$15.44	\$15.79	\$16.12	\$16.42	\$16.71	\$16.97	\$17.22	\$17.45	\$17.67	\$17.87	\$18.06
9 8	Net Present Value -2012						\$2.70	\$3.92	\$5.05	\$6.11	\$7.10	\$8.02	\$8.88	\$9.69	\$10.44	\$11.14	\$11.79	\$12.40	\$12.97	\$13.50	\$14.00	\$14.46	\$14.89	\$15.29	\$15.67	\$16.02	\$16.35	\$16.65	\$16.94	\$17.21	\$17.45	\$17.69	\$17.90	\$18.10
51	Discount Rate (real) ¹	+																																
52	TERASEN GAS																															<u> </u>		
63	Rate of Inflatio																												_					
5	TG		+ +																															
6	BC HYDRO	0.0270																																
57	Rate of Inflatio																																	
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60	Footnote 1: Source LR 07053																																	
51																																		
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Utility Levelized Cost per GJ (Lifetime)

\$

45.1

\$

\$

only enter in boxes marked in blue Fortis BC RESIDENTIAL NEW Measure Data for Scrap It Utility Incentive to PER MEASURE partner incentive the participant Incremental Cost \$ 3,708 Total Incentive \$ Participant \$ 3,708 Annual Impact Per Measure GJ Energy Savings per installation 8.6 Average Annnual Energy Savings per Measure Free Rider Rate / Net-to-Gross 0% 1.00 Net-to-Gross Alternate Energy Impact 4 GJ 976 kWh kW/a Alternate Capacity Impact Measure Lifetime 18 Years Estimated lifespan of measure ANNUAL ACTIVITY 2010 NPV Explanatory Notes Total 2010 2011 2012 Number of Installations 0 1 Estimated Participatation Impact 0 Gross Energy Savings (GJ) 8 9 0 9 Extension of Unit Savings x No. of Upgrades Net Energy Savings (GJ) 9 0 9 0 Gross Energy Savings less Free Riders 8 921 0 976 0 Alternate Energy Impact (Increase) (kWh) 976 Other Utility Billed energy impact \$0.00 Alternate Capacity Impact (Increase) (kW/a) Other Utility Billed capacity impact Benefit Cost Summary 2010 NPV \$ Total 2010 2011 2012 **Avoided Revenue Requirements** PV \$ per GJ \$100.98 \$105.31 \$109.10 Energy Purchases 908 Ś Ś 908 Ś 908 -**Utility Program Costs** DSM Incentives - \$ \$ - \$ -Administration 162 162 \$ \$ \$ Subtotal Ś 151 162 \$ 162 \$ ć Partner Program Costs DSM Incentives - \$ - \$ -\$ -Administration \$ \$ - \$ 14 Subtotal Ś Ś Ś Ś ---Participants' Net Costs Incremental Cost 3,708 \$ 3,708 \$ -\$ Subtotal 3,460 3,708 \$ -\$ 3,708 \$ Alternate Savings - Net Energy (Purchases) 1,268 \$ \$ 1,268 \$ \$1.299 PV \$ per kWh Ś Capacity (Purchases) \$ PV\$ per kW/a \$ Subtotal 1,268 \$ \$ 1,268 \$ 1,268 -Ś Total Resource Net Benefit (Cost) (1,435) Ś - \$ (1,693) \$ Avoided Revenue Requirement less Utility less Partners less Participant Costs plus Alternate Savings Ś -

45.1 \$

Informational (for comparison with supply options)

									PROGRA	M							ALTER	INATE					NET PRESEN	VALUE						1	ENEFIT/COST									PARAN	AETERS				
w Initiative Programs - Solar Ai	ir SCT						COSTS (\$000))						SAVI	iGS (GJ)	LIFE	Imp	act	Levelized Cost	Utility Ben	efits (Costs)	Partic	ipant Benefi	s (Costs)	Pro	ogram Net S	avings			Participant						UTILI	πү					PARTIC	IPANT		
FEI			Utility			Partner										Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Ta	Alternate	e Natural Ga	Alternate Energy		Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternate Supply	Discount Rate	Natural Gas NPV	Carbon Tax NPV	Alternate Energy NPV	Alternate Capacity NPV	Natural Gas Tariff	Energy Tariff
		Incentives	Administration	Total	Incentives	Administrati	on Total	Partici	ipant T	stal % Ut	ility % Part	tner % Partic	pant Gros	s Net-t	o-Gross Net		MWh	kW		(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	(\$'000s)	(\$'000s)		ate Impact	SCT	(\$'000s)		\$/GJ		\$/kWh		\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/GJ	\$/kWh
	Label	в	c	D	E	F	G	н	1	1 1	к	L	м	1	N O	Р	Q	R	s	т	U	v	w	×	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AI	AK	AL	AM	AN	AO	AP	AQ	AR	AS
	Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Prog	am De	G+H D,	/1 6/	і н/і	Progra	am Pro	gram MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M × N × AN	M x N x AD	N x (QxAP + RxAQ)	* PV(AJ,P,-O)	PV(AK,P,-Q*I	N) PV(AK,P,-R)	т/р	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/{V+D}	(T+U)/I	(T+U)-I	Input	Program	Input	Input	Input	PV(AM,P,- InputD25)	Input	PV(AM,P,- InputD28)	PV(AM,P,- InputD29)	Input	Input
2011 <u>SIDENTIAL:</u> Solar Air		0	5	5	0		0	0	39	45	12%	0%	88%	48	100% 48	25	0	-	6	17	N/A	8	1	N/A	A 832	! 1	D -	. 3.	3 39	10	0.2	1.3	0.4	(28)	3.00%	276.02	3%	2.09	3.0%	174.11	26.03	1.44	0.00	9.999	0.083
	Total Residential	0	5	5	0		0	0	39	45	12%		88%	48	48		0	0	6	17	N/A	8	1	N/A	832	N/	6 N/6	3	3 39	10	0.2	13	0.4	(28)	0.5	(22)									

· · · ·	D			-		0				14				~		-	-	0					N N	V I			4.5	10	40		45	10		. 1
1 UTILITY	В	C FORTIS BC	D	E	F	G	Н	I	J	К	L	М	N	0	Р	Q	R	S		U	V	W	Х	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
		FURIISBU																																
2	1	1	1 1	1			1	1	1	L.	1		1	1	1	1	1	1	1	I.	1	1	I.	1	I.	1	1	1	1	1	I.	1	1	
4	I	Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5		Units	1	2011	2012	2015	2014	2010	2010		2010	2019	2020	2021	2022	2020	2024	2020	2020	2027	2020	2022	2000	2001	2002	2000	2004	2000	2000	2007	2000	2009	2040	2041
6	NATURAL GAS																																	
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28
8 1		Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
9	carbon tax	\$ per GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	Distribution adder Total incremental cost of gas including car	\$ per GJ	0.16	0.16 15.44	0.16 15.44	0.16 15.44		0.16 15.44		0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44		0.16 15.44	0.16 15.44		0.16 15.44	15.28									
12 2	GDP Deflator	1001	1.00	1.00			1.00	1.00		1.00	1.00		1.00	1.00	1.00		1.00	1.00		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00
13 3	Incremental Cost of Gas (Real)		\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44		\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.28
14 4	Net Present Value -2010			\$29.54			\$70.71	\$83.64		\$108.38	\$120.22		\$142.86	\$153.69	\$164.20		\$184.32	\$193.94		\$212.35	\$221.16		\$238.01	\$246.07	\$253.89	\$261.48	\$268.86	\$276.02		\$289.72	\$296.27	\$302.63	\$308.81	\$314.74
15 5	Net Present Value -2011				\$29.54	\$43.67	\$57.39	\$70.71	\$83.64	\$96.20	\$108.38		\$131.71	\$142.86	\$153.69	\$164.20	\$174.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07	\$253.89	\$261.48	\$268.86		\$282.97	\$289.72	\$296.27	\$302.63	\$308.74
10 0	Net Present Value -2012					\$29.54	\$43.67	\$57.39	\$70.71	\$83.64	\$96.20	\$108.38	\$120.22	\$131.71	\$142.86	\$153.69	\$164.20	\$174.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07	\$253.89	\$261.48	\$268.86	\$276.02	\$282.97	\$289.72	\$296.27	\$302.56
18																																		
19	ELECTRICITY		1 1																															
20	Incremental Cost of Elec	\$ Per kWh	\$0.12																															
21	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00																															
22																																		
23	1		+ +																															
2 3 4 5 6 7 8 1 9 10 11 12 2 13 3 14 4 15 5 16 6 17 18 19 20 21 22 23 34 25 RETAIL 26 RETAIL 27 28 30 31 32 33 34 35 36 37 38 39 40 TAX	I.	L	1 1																															
26			Rate	Customers		789.928	Total Customers in F	BC	80.000 Tota	al Residential and	d Commercial C	'ustomers on VI																						
27	Residential Retail	-	Kuit	000's		107,720	rour customers in r		00,000 100		a connerent c																							
28		SI \$ Per MJ	\$0.0100	640		712,304	Total Residential Cus	stomers in BC																										
29	TGV		\$0.0143	72																														
30	Electricity		\$0.0230 \$0.0827	1.611																														
32		\$ per kWh \$ per kW per year	\$0.0027	1,511		1,511,435	Total BCH Residents	ial Customers in	BC		89%																							
33	Commercial Retail	5 per kw per year																																
34	те	S Per MJ	\$0.0094	78		77,624	Total Commercial Cu	ustomers in BC																										
35	TGV		\$0.0169	8																														
36	Electricity		\$0.0214	100																														
38		S per kWh S per kW per year	\$52,0000	190		189,764	Total Light Industrial	and Commerci	al Customers in BC																									
39	Licothold	o per un per yeur	\$52.0000	1.0																														
40 TAX	1																																	
41 42 1 43 2		Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
42 1		Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
43 2	Carbon	\$ Per tonne	+	\$20.00			\$30.00	\$30.00		\$30.00	\$30.00			\$30.00	\$30.00		\$30.00	\$30.00		\$30.00	\$30.00		\$30.00	\$30.00		\$30.00	\$30.00	\$30.00		\$30.00	\$30.00	\$30.00	\$30.00	\$30.00
44 3 45 4	Carbon GDP Deflator	\$ Per GJ	+ +	\$0.9976	\$1.2470	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964
45 4	Carbon (Real)		+ +	1.00	1.00	\$1.50	\$1.50	\$1.50		\$1.50	\$1.50		\$1.50	\$1.50	1.00 \$1.50	1.00	\$1.50	\$1.50	1.00	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	1.00	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50
47 6	Net Present Value -2010			÷1.00	\$2.14	\$3.51	\$4.84	\$6.13	\$7.39	\$8.60	\$9.78		\$12.05	\$13.13	\$14.18	\$15.19	\$16.18	\$17.14	\$18.08	\$18.98	\$19.86	\$20.71	\$21.54	\$22.35	\$23.13	\$23.89	\$24.62	\$25.34		\$26.71	\$27.36	\$27.99	\$28.61	\$29.21
48 7	Net Present Value -2011					\$2.62	\$3.99	\$5.32	\$6.61	\$7.86	\$9.08	0.000	\$11.41	\$12.52	\$13.60	\$14.65	\$15.67	\$16.66	\$17.62	\$18.55	\$19.46	\$20.34	\$21.19	\$22.02	\$22.82	\$23.61	\$24.36	\$25.10	\$25.81	\$26.51	\$27.18	\$27.84	\$28.47	\$29.09
49 8	Net Present Value -2012		+				\$2.86	\$4.23	\$5.56	\$6.85	\$8.11	\$9.32	\$10.50	\$11.65	\$12.76	\$13.85	\$14.90	\$15.91	\$16.90	\$17.86	\$18.80	\$19.70	\$20.58	\$21.43	\$22.26	\$23.07	\$23.85	\$24.61	\$25.34	\$26.06	\$26.75	\$27.42	\$28.08	\$28.71
50	Discount Rate (real) ¹		<u> </u>																															
52	TERASEN GAS		1 1																															
53	Rate of Inflatio	n 1.90%	1 1																															
54	TG	3.00%																																
55	TGV	1 3.00%	\downarrow \downarrow																															
56	BC HYDRO	2.00%	+																															
58	Rate of Inflatio BC Hydr		+ +																															
59	Custome		1 1																															
60	Footnote 1: Source LR 07053																																	
61							-																											
62			SHEET LABE	ELS																														
63 New Constructio			BASEBOARD	_																														
65	Solar Air		HEATPUMP	U																														
66																																		

1	FORTIS BC
,	Commercial

Commercial						
NEW						I
Measure Data for Solar Air	r					
PER MEASURE			Utility Incentive to the participant	partner incentive		
Incremental Cost	\$ 39,400					
Total Incentive				\$-		
Participant	\$ 39,400					
Annual Impact Per Measure						
Energy Savings per installation	47.8	GJ		Average Annnual Energy Savi	ngs per Measure	
Free Rider Rate / Net-to-Gross	0%	1.00	_	Net-to-Gross		
Alternate Energy Impact		GJ	0	kWh		
Alternate Capacity Impact		kW/a				
Measure Lifetime	25	Years	Estimated lifespan of m	easure		
ANNUAL ACTIVITY	2009 NPV	Total	2010	2011	2012	Explanatory Notes
Number of Installations						
	1	1	0	1		Estimated Participatation
Impact						
Gross Energy Savings (GJ)	45	48	0	48	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	45	48	0	48	0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	0	0	0	0	0	Other Utility Billed energy impact
Alternate Capacity Impact (Increase) (kW/a)	0 \$0.00		0	0	0	Other Utility Billed energy impact Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary			0 <u>2010</u>	0 <u>2011</u>	0 <u>2012</u>	
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements	\$0.00	-	2010	<u>2011</u>	2012	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ	\$0.00	<u>\$ Total</u>	<u>2010</u> \$276.02	<u>2011</u> \$276.02	<u>2012</u> \$276.02	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases	\$0.00	<u>\$ Total</u>	<u>2010</u> \$276.02	<u>2011</u>	<u>2012</u> \$276.02	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases	\$0.00	<u>\$ Total</u>	<u>2010</u> \$276.02 \$	<u>2011</u> \$276.02 \$ 13,185	<u>2012</u> \$276.02 \$	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases	\$0.00	<u>\$ Total</u> \$ 13,185 \$ -	<u>2010</u> \$276.02 \$ \$	<u>2011</u> \$276.02 \$ 13,185 \$	<u>2012</u> \$276.02	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs	\$0.00	<u>\$ Total</u> <u>\$ 13,185</u>	<u>2010</u> \$276.02 \$ \$	<u>2011</u> \$276.02 \$ 13,185	<u>2012</u> \$276.02 \$	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration	\$0.00	- <u>\$ Total</u> ; <u>\$ 13,185</u> ; <u>\$ 5,250</u>	<u>2010</u> \$276.02 \$ - \$ - \$ -	<u>2011</u> \$276.02 \$ 13,185 \$	<u>2012</u> \$276.02 \$ \$	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal	\$0.00 2009 NPV \$ 13,185	- <u>\$ Total</u> ; <u>\$ 13,185</u> ; <u>\$ 5,250</u>	<u>2010</u> \$276.02 \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ \$ 5,250	<u>2012</u> \$276.02 \$ \$	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal	\$0.00 2009 NPV \$ 13,185	- <u>\$ Total</u> ; <u>\$ 13,185</u> ; <u>\$ 5,250</u>	<u>2010</u> \$276.02 \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ \$ 5,250	<u>2012</u> \$276.02 \$ \$	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs	\$0.00 2009 NPV \$ 13,185	↓	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ - \$ 5,250 \$ 5,250	<u>2012</u> \$276.02 \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration	\$0.00 2009 NPV \$ 13,185	↓ <u>\$ Total</u> <u>\$ 13,185</u> <u>\$ 5,250</u> \$ 5,250 \$ 5,250 \$ 5,250	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ - \$ 5,250 \$ 5,250 \$ -	<u>2012</u> \$276.02 \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Subtotal	\$0.00 2009 NPV \$ 13,185 \$ 4,949	↓	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ - \$ 5,250 \$ 5,250 \$ - \$ - \$ - \$ - \$ -	2012 \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal	\$0.00 2009 NPV \$ 13,185 \$ 4,949	↓	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ - \$ 5,250 \$ 5,250 \$ - \$ - \$ - \$ - \$ -	2012 \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost	\$0.00 2009 NPV \$ 13,185 \$ 4,949 \$ -	\$ Total \$ Total \$ 13,185 \$ - \$ 5,250 \$ 5,250 \$ \$ \$ \$ 39,400	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ - \$ 5,250 \$ 5,250 \$ 5,250 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2012 \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal	\$0.00 2009 NPV \$ 13,185 \$ 4,949	\$ Total \$ Total \$ 13,185 \$ - \$ 5,250 \$ 5,250 \$ \$ \$ \$ 39,400	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$13,185 \$ \$ \$ \$ \$,250 \$ \$,250 \$ \$ \$,250 \$ \$ \$,250 \$ \$ \$,250 \$ \$ \$,250 \$ \$ \$,250 \$ \$ \$,250 \$ \$ \$,250 \$ \$ \$,250 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,276,02 \$ \$ \$,250 \$ \$,250 \$ \$,250 \$ \$ \$,250 \$ \$ \$,250 \$ \$,250 \$ \$ \$,250 \$ \$ \$,250 \$ \$,1250 \$ \$,250 \$ \$ \$,250 \$ \$ \$ \$,250 \$ \$ \$,250 \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	2012 \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net	\$0.00 2009 NPV \$ 13,185 \$ 4,949 \$ -	\$ Total \$ Total \$ \$ 13,185 \$ \$ \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 39,400 \$ 39,400	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ - \$ 5,250 \$ 5,250 \$ 5,250 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2012 \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases)	\$0.00 2009 NPV \$ 13,185 \$ 4,949 \$ -	\$ Total \$ Total \$ 13,185 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 39,400 \$ 39,400 \$ 39,400	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ - \$ 5,250 \$ 5,250 \$ 5,250 \$ - \$ - \$ - \$ - \$ - \$ - \$ 39,400 \$ 39,400 \$ -	2012 \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases) Capacity (Purchases)	\$ 0.00 2009 NPV \$ 13,185 \$ 4,949 \$ - \$ 37,138	\$ Total \$ Total \$ 13,185 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 5,250 \$ 39,400 \$ 39,400 \$ - 5	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$13,185 \$ \$5,250\$	2012 \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact
Alternate Capacity Impact (Increase) (kW/a) Benefit Cost Summary Avoided Revenue Requirements PV \$ per GJ Energy Purchases Utility Program Costs DSM Incentives Administration Subtotal Partner Program Costs DSM Incentives Administration Subtotal Participants' Net Costs Incremental Cost Subtotal Alternate Savings - Net Energy (Purchases)	\$0.00 2009 NPV \$ 13,185 \$ 4,949 \$ -	\$ Total \$ Total \$ \$ 13,185 \$ \$ \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 5,250 \$ \$ 39,400 \$ 39,400 \$ \$ \$	<u>2010</u> \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2011 \$276.02 \$ 13,185 \$ - \$ 5,250 \$ 5,250 \$ 5,250 \$ - \$ - \$ - \$ - \$ - \$ - \$ 39,400 \$ 39,400 \$ -	2012 \$276.02 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Other Utility Billed capacity impact

Fortis BC																																													
								PROGRAM								ALTER	RNATE				N	IET PRESENT	VALUE							BENEFIT/CO	IST								PARAME	IETERS					
New Initiative Programs - Solar AirTRC					cc	OSTS (\$000)						s	AVINGS (GJ)		LIFE	Imp	pact	Levelized Cost	Utility Be	nefits (Costs)	Particip	oant Benefits	(Costs)	Prog	am Net Sav	vings			Participant						UTIL	YTL					PARTICIP	PANT			
		Utility			Partners										Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternate Supply	Discount Rate				Alternate Capacity NPV	Natural Gas Tariff E	Energy Tariff	Capacity Tariff
	Incentives	Administration	Total	Incentives	Administration	Total	Participar	nt Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWh	kW		(\$'000s)	(\$'000s)	(\$*000s)	(\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	(\$*000s)	(\$'000s)		Rate Impact	Total Resource	(\$'000s)		\$/GJ	, I	\$/kWh	i I	\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/GJ	\$/kWh	\$/kW/a
Labe	8	c	D	E	F	6	н	1	1	к	L	м	N	0	Р	Q	R	s	т	U	v	w	х	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
Source Sheet or Calculation	n Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	6/1	н/і	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q×N×AL	M×N×AN	M x N x AD	N x (QxAP + RxAQ)	PV(ALP,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	Input	Program	Input	Input	Input	PV(AM,P,- InputD25)	Input	PV(AM,P,- InputD28)	PV(AM,P,- InputD29)	Input	Input	Input
2011 <u>Schools</u> Solar Air	0	5	5	0	0		0 3	39 45	5 129	0%	88%	48	100%	48	25	0	-	10	6	i N/A	6	1	N/A	549	-	-	1.1	39	7	0.2	0.5	0.1	(39)	7.15%	125.59	6%	1.53	6.0%	127.82	17.22	1.06	0.00	9.999	0.083	-

A	B	С	D	E	F	G	Н		J	К	1	М	N	0	Р	Q	R	S	т	U	V	W	х	Y	Z	AA	AB	AC	AD	AE	AE	AG	AH	AI
1 UTILITY	В	Fortis BC	D	L	1	0			J	K	L	IVI	IN	U		Q	K	5	'	0	v	**	~		2	74	AD	AC	AD	AL	Ai	AG		
2		1010020																																
2 3 4 5 6		1								1			1	1	1	1	1	1			1	1			1	1	1	1				1		
4		Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5	NUTERIA CLO	Units																																
5	NATURAL GAS Incremental Cost of Gas (nominal)	\$ Per GJ	\$5.50	\$6.17	\$6.81	\$7.35	\$7.87	\$8.26	\$8,56	\$8.78	\$8.99	\$9.19	\$9.40	\$9.60	\$9.81	\$10.03	\$10.25	\$10.47	\$10.70	\$10.93	\$11.17	\$11.42	\$11.67	\$11.92	\$12.19	\$12.45	\$12.73	\$13.01	\$13.29	\$13.58	\$13.88	\$14.19	\$14.50	\$14.92
7 8 1	incrementar Cost of Gas (nonlinar)	Year	0	30.17	2	31.55	4	5 5	6	30.70	38.99 8	9	39.40 10	39.00	12	13	14	310.47	16		18	\$11.42 19	20	21	22	23	24	25	26	27	28	29	30	314.62
9	carbon tax	\$ per GJ	0.75	1.00	1.25	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50		1.50	1.50		1.50	1.50		1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
10	Distribution adder	\$ per GJ	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16		0.16			0.16	0.16		0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	
11 12 2	Total incremental cost of gas including ca GDP Deflator	rbon	6.41	7.32		9.01 1.00	9.52	9.92	10.22	10.43	10.64	10.85		11.26	11.47	11.68	11.90	12.13		12.59	12.83	13.07	13.32	13.58	13.84	14.11 1.00	14.38	14.66 1.00	14.95	15.24	15.54	15.84	16.15	16.31
13 3	Incremental Cost of Gas (Real)		\$6.41							\$10.43	\$10.64			\$11.26	\$11.47		\$11.90	\$12.13		\$12.59	\$12.83	\$13.07	\$13.32	\$13.58	\$13.84	\$14.11	\$14.38	\$14.66	\$14.95	\$15.24	\$15.54	\$15.84	\$16.15	\$16.31
14 4	Net Present Value -2010			\$12.36						\$51.47	\$57.19	402100		\$72.71	\$77.39	\$81.83	\$86.05	\$90.07	\$93.89	\$97.52	\$100.98		\$107.39	\$110.36			\$118.43	\$120.87		\$125.39	\$127.49	\$129.48	\$131.38	\$133.17
15 5	Net Present Value -2011				\$13.99		\$28.54 \$23.25			\$48.75	\$54.87			\$71.51	\$76.51	\$81.27	\$85.80	\$90.10	\$94.20	\$98.09 \$97.78	\$101.79	\$105.31	\$108.66	\$111.84	\$114.87	\$117.75	\$120.49	\$123.10		\$127.95	\$130.19	\$132.33	\$134.37	\$136.28
10 0	Net Present Value -2012					\$15.51	\$23.25	\$30.78	\$38.01	\$44.91	\$51.47	\$57.71	\$63.65	\$69.29	\$74.66	\$79.76	\$84.61	\$89.22	\$93.61	\$97.78	\$101.74	\$105.51	\$109.10	\$112.51	\$115.76	\$118.85	\$121.79	\$124.58	\$127.24	\$129.77	\$132.18	\$134.47	\$136.65	\$138.70
18		-																																
19	ELECTRICITY																																	
9 9 10 11 12 13 3 14 4 4 15 5 6 6 17 16 6 17 19 20 21 22 22 22 22 22 22 22 22 22	Incremental Cost of Elec	\$ Per kWh	\$0.12																															
21	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00																															
23																																		
24																																		
25 RETAIL																																		
26	Residential Retail		Rate	Customers		789,928	Total Customers	in BC	80,000	Total Residential an	d Commercial C	Customers on VI																						
28		SI \$ Per MJ	\$0.0100	640		712.304	Total Residential	Customers in BC																										
29		VI S Per MJ	\$0.0143	72		112,004	10ur residentia	customets in De																										
30		y \$ Per MJ																																
31		y \$ per kWh	\$0.0827	1,511		1,511,435	Total BCH Resid	ential Customers in	in BC		89%																							
33	Commercial Retail	y \$ per kW per year																																
34		SI \$ Per MJ	\$0.0094	78		77,624	Total Commercia	l Customers in BC	2																									
35		/I \$ Per MJ	\$0.0169	8																														
36		y \$ Per MJ y \$ per kWh	\$0.0214	100		190.764	Tetel Liebs Indon	rid and Community	i-1 Contempo in D	-																								
38		y \$ per kW per year	30.0707	190		169,704	Total Light Indus	that and Commerc	cial Customers in B	~																								
39																																		
40 TAX																																		
41		Year	. 2009		2011	2012				2016	2017			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
42 1	Carbon	Year \$ Per tonne		0	1 \$25.00	2	3 \$30.00	4 \$30.00	5	6 \$30.00	\$30.00	8 \$30.00	9 \$30.00	10 \$30.00	11 \$30.00	12 \$30.00	13 \$30.00	14 \$30.00	15 \$30.00	16 \$30.00	17 \$30.00	18 \$30.00	19 \$30.00	20 \$30.00	21 \$30.00	\$30.00	\$30.00	24 \$30.00	25 \$30.00	26 \$30.00	\$30.00	28 \$30.00	29 \$30.00	30 \$30.00
44 3	Carbon	\$ Per GJ		\$0.9976	440100					\$1.4964	\$1.4964			\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964
41 42 43 43 44 45 4 46 5	GDP Deflator			1.00			1.00			1.00	1.00			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00
46 5 47 6	Carbon (Real) Net Present Value -2010	-	-	\$1.00	\$1.25	\$1.50	\$1.50	\$1.50 \$5.43	4100	\$1.50 \$7.34	\$1.50 \$8.20	\$1.50 \$9.00		\$1.50 \$10.45	\$1.50 \$11.11	\$1.50	\$1.50 \$12.29	\$1.50 \$12.82	\$1.50 \$13.31	\$1.50 \$13.78	\$1.50 \$14.21	\$1.50 \$14.61	\$1.50 \$14.99	\$1.50 \$15.34	\$1.50 \$15.67	\$1.50 \$15.97	\$1.50 \$16.26	\$1.50 \$16.52	\$1.50 \$16.77	\$1.50 \$17.00	\$1.50 \$17.22	\$1.50 \$17.42	\$1.50 \$17.61	\$1.50 \$17.79
48 7	Net Present Value -2010	1			\$2.02	\$3.23 \$2.47	\$4.57			\$7.34 \$6.87	\$8.20			\$10.45	\$11.11 \$10.90	÷	\$12.29 \$12.17	\$12.82 \$12.74	\$13.31	\$13.76	\$14.21 \$14.23	\$14.61	\$14.99 \$15.06	\$15.34	\$15.67 \$15.79	\$15.97 \$16.12	\$16.26	\$16.52		\$17.00	\$17.22 \$17.45	\$17.42	\$17.61 \$17.87	\$17.79 \$18.06
49 8	Net Present Value -2012						\$2.70			\$6.11	\$7.10			\$9.69	\$10.44		\$11.79	\$12.40	\$12.97	\$13.50	\$14.00	\$14.46	\$14.89	\$15.29	\$15.67	\$16.02	\$16.35	\$16.65		\$17.21	\$17.45	\$17.69	\$17.90	\$18.10
50 51	Discount Data (cont)1																																	
52	Discount Rate (real) ¹ TERASEN GAS	+	+																															
53	Rate of Inflatio	n 1.90%																																
54	т																																	
55	TG	6.89%																																
57	BC HYDRO Rate of Inflatio	n 2.00%	+																															
58	BC Hyde																																	
59	Custom	er 6.00%																																
60	Footnote 1: Source LR 07053	1																																
62		+	1																															
63	1	1																																
64																																		
65	_		-																															
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Fortis BC

Fortis BC			only onto	i in boxes man		
Commercial						
NEW						
<mark>Meas</mark> ure Data for Solar Aii	r					
PER MEASURE			Utility Incentive to the participant	partner incentive		
Incremental Cost	\$ 39,400	1				
Total Incentive						
Participant Annual Impact Per Measure	\$ 39,400					
Energy Savings per installation	47.8	GJ		Average Annnual Energy Savi	ngs per Measure	
Free Rider Rate / Net-to-Gross		1.00		Net-to-Gross		
Alternate Energy Impact		GJ	0	kWh		
Alternate Capacity Impact		kW/a				
Measure Lifetime	25	Years	Estimated lifespan of m	easure		
ANNUAL ACTIVITY	2010 NPV	Total	2010	2011	2012	Explanatory Notes
Number of Installations	2010 NPV	lotal	2010	2011	<u>2012</u>	
	1	1	0	1		Estimated Participatation
Impact			, v	*		
Gross Energy Savings (GJ)	45	48	0	48	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	45		0	48	0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)			0	0	0	Other Utility Billed energy impact
Alternate Capacity Impact (Increase) (kW/a)	\$0.00					Other Utility Billed capacity impact
Benefit Cost Summary						
	<u>2010 NPV</u>	<u>\$ Total</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	_
Avoided Revenue Requirements						
PV \$ per GJ		1.	\$120.87			7
Energy Purchases	\$ 5,999	9 <u>\$ 5,999</u>	<u>\$</u>	\$ 5,999	<u>\$</u> -	<u>-</u>
Jtility Program Costs		1.				
DSM Incentives			\$-	\$ -	\$ -	
Administration		\$ 5,250		\$ 5,250		
Subtotal	\$ 4,900	\$ 5,250	\$ -	\$ 5,250	\$ -	_
Partner Program Costs			<u>,</u>		<u>,</u>	
DSM Incentives		\$ -	\$ - \$ -	\$ - \$ -	\$ - \$ -	
Administration		<u>\$</u>	<u>*</u>	-	-	1
Subtotal	\$-	\$ -	\$ -	\$-	\$ -	-
Participants' Net Costs		ć 20.400	ć	Ś 39.400	\$ -	
Incremental Cost	A	\$ 39,400	<u>\$</u>		2	-
Subtotal	\$ 36,771	\$ 39,400	\$ -	\$ 39,400	\$ -	-
Alternate Savings - Net Energy (Purchases)		\$ -	\$ -	\$ -	\$-	\$1.534 PV \$ per kWh
Capacity (Purchases)		- د	ş - \$ -	ş - \$ -	ş - Ś -	PV\$ per kW/a
Subtotal	ć	<u>, -</u> Ś -	<u>, -</u> \$ -	<u> </u>	<u>, -</u> \$ -	
Total Resource Net Benefit (Cost)	\$ - \$ (35,672		\$ - \$ -	\$		Avoided Revenue Requirement less Utility less Partners less Participa
Utility Levelized Cost per GJ (Lifetime)	\$ 81.3	-	\$ -	\$ 81.3		Informational (for comparison with supply options)
,	. 51.5		•	. 01.3		

ORTIS BC																		T	ALTERN														DENIER II	007			- 1												
									PRO	OGRAM									ALTERN	ATE				N	IET PRESEN	IT VALUE				_			BENEFIT/C	OST			_						PARAM	ETERS					
New Initiative Programs - Solar Commercial SCT							COSTS (\$0	100)							SAV	INGS (GJ)		LIFE	Impa	ct	Levelized Cost	Utility Bene	fits (Costs)	Particip	pant Benef	its (Costs)		Program Net	Savings			Particip	pant						UTILITY						PARTIC	IPANT			
FEI			Utility			Partne	ß											Years	Energy	Capacity	(\$/GJ)	Program	Alternate	Program	Carbon Ta	ax Alternate	Natural G	Sas Altern Energ		e Natura y Gas	Total Cos		nefits Benefit/Co	st Natur Gas		Benefi	Rate	lity Ga		ount	ternate E iupply		Natural Gas NPV	Carbon Tax NPV	Alternate Energy NPV	Alternate Capacity NPV	Natural Gas Tariff	Energy Tariff	Capacity Tariff
	In	centives A	dministration	Total	Incentives	Administra	tion To	tal I	Participant	Total	% Utility	% Partner	% Participa	nt Gros	is Net	to-Gross	Net		MWh	kW		(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(\$'000s)	(GJ)	(MW?	(kw)	Utility	(\$'000s	s) (\$*001	10s)	Rate Imp	act SCT	(\$'000	ls)	\$/0	a l		\$/kWh		\$/GJ	\$/GJ	\$/kWh	\$/kW/a	\$/GJ	\$/kWh	\$/kW/a
	Label	в	c	D	E	F		6	н		1	к	L	м		N	0	Р	Q	R	s	т	U	v	w	×	Y	z	AA	AB	AC	AD	AE	AF	AG	AH	AI	A	A	ĸ	AL	AM	AN	AO	AP	AQ	AR	AS	AT
Source Sheet or Calcu	lation P	Program	Program	B+C	Program	Program	n 6	• F	Program	D+G+H	D/I	G/I	н/1	Progra	am P	ogram	MxN	rogram	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AG	N x (QxAP + RxAQ)	PV(AI,P,-C	0) PV(AK,P,-	(*N) PV(AK,P,-I	R) T/D	H>0, (V+W)<0 H<0, (V+W)>	0, AD/AC	T/(V+E) (T+U)/	(T+U)-	l Input	Progr	am Inp	out	Input	Input	PV(AM,P,- InputD25)	Input	PV(AM,P,- InputD28)	PV(AM,P,- InputD29)	Input	Input	Input
2011 R <u>ESIDENTIAL:</u> Solar Com		0	4	4	0		0	0	55	59	6%	05	6 94	196	76	100%	76	25	0	-	3	27	N/A	13		2 N/A			0		7.3 5	55	15 0.	3	L.6 (5	(31) 3.005	6 271	5.02	3%	2.09	3.0%	174.11	26.03	1.44	0.00	9.999	0.083	
Total Resider	ntial	0	4	4	0		0	0	55	59	6%		94	196	76		76		0	0	3	27	N/A	13		2 N/A	1.3	31	I/A N	/A 7	7.3 5	55	15 0.	3	1.6 0	5	(31)	0.6	(23)										

	P	<u> </u>		-	- 1	0				K			N	0	D	0	D	0	T		V	14/	V	V	7		AD	4.0	40	A.E.	A.C.	40	A11	
1 UTILITY	В	C FORTIS BC	D	E	F	G	Н	I	J	К	L	М	N	0	Р	Q	R	S		U	V	W	Х	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	Al
		FORTISBU																																
2	1	1	т т	1	1	1	1	1	I I	1	1		1	1	1	1	1	1	1	I.	1	1	I.	1	I.	1	1	1	1	1	I.	1	1	
4	I	Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5		Units	2010	2011	2012	2015	2014	2010	2010		2010	2019	2020	2021	2022	2020	2024	2020	2020	2027	2020	2022	2000	2001	2002	2000	2004	2000	2000	2007	2000	2009	2040	2041
6	NATURAL GAS																																	
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28	\$15.28
8 1		Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16		18	19	20	21	22	23	24	25	26	27	28	29	30	31
9	carbon tax	\$ per GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	Distribution adder Total incremental cost of gas including ca	\$ per GJ	0.16	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44	0.16 15.44		0.16 15.44	0.16 15.44		0.16 15.44	15.28									
12 2	GDP Deflator	1001	1.00	1.00	1.00		1.00	1.00		1.00	1.00		1.00	1.00	1.00		1.00	1.00		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		1.00	1.00	1.00	1.00	1.00
13 3	Incremental Cost of Gas (Real)		\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44		\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.44	\$15.28
14 4	Net Present Value -2010			\$29.54			\$70.71	\$83.64		\$108.38	\$120.22		\$142.86	\$153.69	\$164.20		\$184.32	\$193.94		\$212.35	\$221.16		\$238.01	\$246.07	\$253.89	\$261.48	\$268.86	\$276.02		\$289.72	\$296.27	\$302.63	\$308.81	\$314.74
15 5	Net Present Value -2011				\$29.54	\$43.67	\$57.39	\$70.71		\$96.20	\$108.38		\$131.71	\$142.86	\$153.69	\$164.20	\$174.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07	\$253.89	\$261.48	\$268.86		\$282.97	\$289.72	\$296.27	\$302.63	\$308.74
16 6	Net Present Value -2012					\$29.54	\$43.67	\$57.39	\$70.71	\$83.64	\$96.20	\$108.38	\$120.22	\$131.71	\$142.86	\$153.69	\$164.20	\$174.41	\$184.32	\$193.94	\$203.28	\$212.35	\$221.16	\$229.71	\$238.01	\$246.07	\$253.89	\$261.48	\$268.86	\$276.02	\$282.97	\$289.72	\$296.27	\$302.56
18																																		
19	ELECTRICITY		1 1																															
20	Incremental Cost of Elec	\$ Per kWh	\$0.12																															
21	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00																															
22																																		
2 3 4 5 6 7 8 1 9 10 11 12 2 13 3 14 4 15 5 16 6 17 18 19 20 21 22 23 34 25 RETAIL 26 RETAIL 26 30 31 32 33 34 35 36 37 38 39 40 TAX	1		+ +																															
25 RETAIL	1	L	1 1																															
26			Rate	Customers		789.928	Total Customers in I	BC	80.000 Tot	al Residential and	d Commercial C	'ustomers on VI																						
27	Residential Retail		Kiite	000's		107,720	rour customers in i	<i>D</i> C	00,000 10	III ICONCENTITI III	a connerent c																							
28		GI \$ Per MJ	\$0.0100	640		712,304	Total Residential Cu	istomers in BC																										
29	TG		\$0.0143	72																														
30	Electricity		\$0.0230 \$0.0827	1.611																														
32		y \$ per kWh y \$ per kW per year	00.0027	1,511		1,511,435	Fotal BCH Residenti	hal Customers in	h BC		89%																							
33	Commercial Retail	y s per k w per year																																
34	те	GI \$ Per MJ	\$0.0094	78		77,624	Total Commercial Ci	ustomers in BC																										
35	TG		\$0.0169	8																														
36	Electricity		\$0.0214	100																														
38		y \$ per kWh y \$ per kW per year	\$52,0000	190		189,764	Fotal Light Industria	al and Commerci	nal Customers in BC																									
39	Licenter	per kit per year	452.0000	1.0																														
40 TAX																																		-
41 42 1 43 2		Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
42 1		Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
43 2	Carbon	\$ Per tonne		\$20.00	\$25.00		\$30.00	\$30.00		\$30.00	\$30.00			\$30.00	\$30.00		\$30.00	\$30.00		\$30.00	\$30.00		\$30.00	\$30.00		\$30.00	\$30.00	\$30.00		\$30.00	\$30.00	\$30.00	\$30.00	\$30.00
44 3 45 4	Carbon GDP Deflator	\$ Per GJ	+ +	\$0.9976	\$1.2470	\$1.4964	\$1.4964	\$1.4964		\$1.4964	\$1.4964		\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964	\$1.4964
45 4	Carbon (Real)		+ +	1.00	\$1.25	\$1.50	\$1.50	\$1.50	1.00	\$1.50	\$1.50		\$1.50	\$1.50	1.00 \$1.50	1.00	\$1.50	\$1.50	1.00	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50	1.00	\$1.50	\$1.50	\$1.50	\$1.50	\$1.50
47 6	Net Present Value -2010			÷1.00	\$2.14	\$3.51	\$4.84	\$6.13	\$7.39	\$8.60	\$9.78		\$12.05	\$13.13	\$14.18	\$15.19	\$16.18	\$17.14	\$18.08	\$18.98	\$19.86	\$20.71	\$21.54	\$22.35	\$23.13	\$23.89	\$24.62	\$25.34		\$26.71	\$27.36	\$27.99	\$28.61	\$29.21
48 7	Net Present Value -2011					\$2.62	\$3.99	\$5.32	\$6.61	\$7.86	\$9.08	0.000	\$11.41	\$12.52	\$13.60	\$14.65	\$15.67	\$16.66	\$17.62	\$18.55	\$19.46	\$20.34	\$21.19	\$22.02	\$22.82	\$23.61	\$24.36	\$25.10	\$25.81	\$26.51	\$27.18	\$27.84	\$28.47	\$29.09
49 8	Net Present Value -2012		+ +				\$2.86	\$4.23	\$5.56	\$6.85	\$8.11	\$9.32	\$10.50	\$11.65	\$12.76	\$13.85	\$14.90	\$15.91	\$16.90	\$17.86	\$18.80	\$19.70	\$20.58	\$21.43	\$22.26	\$23.07	\$23.85	\$24.61	\$25.34	\$26.06	\$26.75	\$27.42	\$28.08	\$28.71
50	Discount Rate (real) ¹		+ +																															
52	TERASEN GAS		+ +																															
53	Rate of Inflatio	n 1.90%	1 1																															
54	те	3.00%																																
55	TG	VI 3.00%	I																															
56	BC HYDRO	- 2.00%	+ +																															
58	Rate of Inflatio BC Hydr		+ +																															
59	Custome		+ +																															
60	Footnote 1: Source LR 07053																																	
61																																		
62			SHEET LABE	ELS																														
63 New Construction			BASEBOARD	_																														
65	Solar Com	0	HEATPUMP	U					<u>├</u>																									
66	'	Ť																																
																																		-

FORTIS BC			only enter	r in boxes mark	ed in blue	e
Commercial			-			
NEW						
Measure Data for Solar Co	m					
PER MEASURE			Utility Incentive to	partner incentive		
			the participant			
Incremental Cost	\$ 54,772					
Total Incentive				\$ -		
Participant	\$ 54,772					
Annual Impact Per Measure		a i				
Energy Savings per installation	76.4	GJ		Average Annnual Energy Savin	gs per Measure	
Free Rider Rate / Net-to-Gross	-	1.00		Net-to-Gross		
Alternate Energy Impact		GJ	0	kWh		
Alternate Capacity Impact	25	kW/a				
Measure Lifetime	25	Years	Estimated lifespan of me	easure		
ANNUAL ACTIVITY	2009 NPV	Total	2010	2011	2012	Explanatory Notes
Number of Installations	2003 INF V	<u>rota</u>	2010	<u>2011</u>	2012	
	1	1	0	1		Estimated Participatation
Impact				-		
• Gross Energy Savings (GJ)	72	76	0	76	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	72		0	76	0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	0		0	0	0	Other Utility Billed energy impact
Alternate Capacity Impact (Increase) (kW/a)	\$0.00		Ũ	0	Ū	Other Utility Billed capacity impact
Alternate capacity impact (increase) (kw/a)	\$0.00					
Benefit Cost Summary						
Serielle Gost Sammary	2009 NPV	\$ Total	2010	2011	2012	
Avoided Revenue Requirements	20051111	<u>p rotar</u>	2010		EUTE	-
PV \$ per GJ			\$276.02	\$276.02	\$276.0	2
Energy Purchases	\$ 21,094	\$ 21,094		\$ 21,094		
Utility Program Costs	. ,	<u> </u>	<u></u>	<u> </u>	·	<u>-</u>
DSM Incentives		<u>ج</u> ج	\$-	\$-	\$-	
Administration		\$ 3,750	\$ -	\$3,750.00	÷ -	
	¢ 3.535		<u>*</u>		ć	
Subtotal Partner Program Costs	\$ 3,535	\$ 3,750	ş -	\$ 3,750	ə -	_
Partner Program Costs		ś -	ć	s -	\$ -	
DSM Incentives			\$ -	ې -		
Administration			<u> </u>	<u>ə</u>	\$.	1
Subtotal	\$ -	\$-	\$ -	\$ -	\$ -	_
Participants' Net Costs			<u>,</u>	<u>ـــــ</u>	<u>,</u>	
Incremental Cost		<u>\$ 54,772</u>	<u>\$</u>	\$ 54,772		-
Subtotal	\$ 51,628	\$ 54,772	\$-	\$ 54,772	\$ -	_
Alternate Savings - Net			<u>^</u>	A	<u>,</u>	
Energy (Purchases)		\$ -	\$ -	\$ -	\$ -	\$2.090 PV \$ per kWh
Capacity (Purchases)		<u>\$</u>	<u>\$</u> -	<u>\$</u>	<u>\$</u> -	PV\$ per kW/a
Subtotal	\$ -	\$-	\$ -	\$ -	\$ -	
Total Resource Net Benefit (Cost)	\$ (34,068)		\$ -	\$ (37,428)		Avoided Revenue Requirement less Utility less Partners less Participan
Utility Levelized Cost per GJ (Lifetime)	\$ 44.0		\$-	\$ 44.0	\$-	Informational (for comparison with supply options)

Fortis BC																		n																											
								Pf	OGRAM								ALTERNAT	E				NET P	PRESENT V	ALUE							BENEFIT/C	COST								PARAME	FERS				
New Initiative Commercial Tl	Programs - Solar C					со	STS (\$000)						5	SAVINGS (GJ)		LIFE	Impact		evelized Cost	Itility Benefit	s (Costs)	Participant	: Benefits ((Costs)	Pro	ogram Net Sa	ivings			Participa	ant					UTI	.ITY					PARTICIPAN	іт		
			Utility			Partners										Years	Energy Ca	pacity	(\$/GJ)	Program Al	lternate f	Program Car	rbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Cost	s Total Bene	fits Benefit/Co	ost Natural Gas		TRC Net Benefits	Natural Gas Utility Discount Rate	Natural Gas Supply	Alternate Discount Rate	Alternate Supply			Carbon Tax NPV		ernate pacity NPV	ral Gas Energy ariff	Capacity Tariff Tariff
		Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner %	6 Participant	Gross	Net-to-Gross	Net		MWh	kW		(\$'000s) (\$'000s)	(\$'000s) (\$	\$'000s)	(\$'000s)	(GJ)	(MWh)	(kW)	Utility	(\$'000s)) (\$'000s	5)	Rate Impac	Total Resource	e (\$'000s)		\$/GJ		\$/kWh		\$/GJ	\$/GJ \$	\$/kWh \$/k	′kW/a \$/0	/GJ \$/k	Wh \$/kW/a
	Lab	pel B	с	D	E	F	G	н	I	J	к	L	м	N	0	Р	Q	R	s	т	U	v	w	х	Y	Z	AA	АВ	AC	AD	AE	AF	AG	АН	AI	AJ	AK	AL	АМ	AN	AO	AP /	AQ AI	AR A	5 AT
	Source Sheet or Calculation	on Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	н/і	Program	Program	MxN	Program	Program Pr	ogram	D/Y	OxAJ Q	Q x N x AL	/IXNXAN M	x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)) PV(AK,P,-R)	T/D	H>0, (V+W)∙	<0 H<0, (V+W) X)>0, AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	Input	Program	Input	Input	Input	PV(AM,P,- InputD25)		PV(AM,P,- PV(A nputD28) Input	AM,P,- utD29) Inp	iput Ing	ut Input
Schools	2011			· ·		>	4			·	·						, ,			,		·										'	¢						,			`		, ,	
Solar Com			0	4	4 () (0 () 55	59	6%	0%	94%	76	100%	76	25	0	-	4	10	N/A	10	1	N/A	879	-		- 2.6	5 5	5 :	11 0	.2 0.7	0.2	(49	9) 7.15%	125.59	6%	1.53	6.0%	127.82	17.22	1.06	0.00 9	9.999 (.083 -
								1																				I																	

	B	С	D		F	G	нГ		J	K	1	М	N	0	Р	Q	R	8	<u>т</u> Т	U	V	W	x	Y	7	AA	AB	AC	AD	AE	ΛE Ι	AG	AH	AI
1 UTILITY		Fortis BC			1	0			5	Κ	L]	IVI	IN	0		Q	IX.	3	I 1	0	v	VV	~	1	2							70		
2	1	1	1	1	I	1	I	I	1		I	I		I	I I	I		1	I	1	I		I	I	I I	I	1	1		I	I	I	l	
4		Year	2010) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
5	NATURAL GAS	Units																																
7	Incremental Cost of Gas (nominal)	\$ Per GJ	\$5.50) \$6.17	\$6.81	\$7.35	\$7.87	\$8.26	\$8.56	\$8.78	\$8.99	\$9.19	\$9.40	\$9.60	\$9.81	\$10.03	\$10.25	\$10.47	\$10.70	\$10.93	\$11.17	\$11.42	\$11.67	\$11.92	\$12.19	\$12.45	\$12.73	\$13.01	\$13.29	\$13.58	\$13.88	\$14.19	\$14.50	\$14.82
8 1 9	carbon tax	Year \$ per GJ	0	1	2	3 1.50	4	5	6	7 1.50	8	9	10 1.50	11	12	13 1.50	14 1.50	15 1.50	16 1.50	17 1.50	18 1.50	19 1 50	20	21	22 1.50	23	24	25 1.50	26 1.50	27	28	29 1 50	30 1.50	31 1.50
10	Distribution adder	\$ per GJ	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16		0.16	0.16	
11 12 2	Total incremental cost of gas including ca GDP Deflator	urb <u>on</u>	6.41	7.32	8.21	9.01	9.52 1.00	9.92	10.22	10.43	10.64	10.85	11.05	11.26	11.47	11.68	11.90	12.13	12.35	12.59	12.83 1.00	13.07	13.32	13.58	<i>13.84</i> 1.00	14.11	14.38	14.66 1.00	14.95	15.24	15.54	15.84	<i>16.15</i> 1.00	<i>16.31</i> 1.00
13 3 14 4	Incremental Cost of Gas (Real) Net Present Value -2010		\$6.41	\$7.32 \$12.36	\$8.21 \$19.03	\$9.01 \$25.87	\$9.52 \$32.61	\$9.92 \$39.16	\$10.22 \$45.47	\$10.43 \$51.47	\$10.64 \$57.19	\$10.85 \$62.63	\$11.05 \$67.80	1	\$11.47 \$77.39	\$11.68 \$81.83	\$11.90 \$86.05		\$12.35 \$93.89	\$12.59 \$97.52	\$12.83 \$100.98	\$13.07 \$104.26	\$13.32 \$107.39	\$13.58 \$110.36			\$14.38 \$118.43	\$14.66 \$120.87		\$15.24 \$125.39	\$15.54 \$127.49	\$15.84 \$129.48	\$16.15 \$131.38	\$16.31 \$133.17
15 5	Net Present Value -2011			\$12.50	\$19.03	\$23.87	\$28.54	\$39.16	\$43.47	\$31.47 \$48.75		\$60.70	\$66.24		\$77107	\$81.83	\$85.80	\$90.07	\$93.89	\$97.52	\$100.98		\$107.39	\$110.38			\$118.43	\$120.87		\$123.39	\$127.49	\$129.48 \$132.33	\$134.37	\$136.28
16 17	Net Present Value -2012					\$15.51	\$23.25	\$30.78	\$38.01	\$44.91	\$51.47	\$57.71	\$63.65	\$69.29	\$74.66	\$79.76	\$84.61	\$89.22	\$93.61	\$97.78	\$101.74	\$105.51	\$109.10	\$112.51	\$115.76	\$118.85	\$121.79	\$124.58	\$127.24	\$129.77	\$132.18	\$134.47	\$136.65	\$138.70
18																																		
19 20	ELECTRICITY Incremental Cost of Elec	\$ Per kWh	\$0.12	2																														
21	Incremental Cost of E Capacity	\$ Per kW/a	\$170.00)																														
23																																		
24 25 RETAIL																																		
26 KETAL			Rate	e Customers		789,928 T	otal Customers in B	3C	80,000 To	otal Residential	and Commercial Cus	tomers on VI																						
27	Residential Retail	GI \$ Per MJ	\$0.0100	000's 640		712.304 7	otal Residential Cus	stomers in BC																										
29	тд	VI \$ Per MJ	\$0.0143	72		712,501																												
30	Electricit Electricit		\$0.0230 \$0.0827	1,511		1,511,435 T	otal BCH Residentia	al Customers in B	BC		89%																							
32	Electricit Commercial Retail	y \$ per kW per year																																
34		GI \$ Per MJ	\$0.0094	78		77,624 Т	otal Commercial Cu	astomers in BC																										
35 36	TG Electricit	VI \$ Per MJ xy \$ Per MJ	\$0.0169 \$0.0214	8																														
37	Electricit	y \$ per kWh	\$0.0769	190		189,764 T	otal Light Industrial	l and Commercial	l Customers in BC																									
38	Electrici	\$ per kW per year	\$52.0000	15																														
40 TAX																																		
41 42 1		Year Year	2009	2010	2011	2012	2013	2014 4	2015	2016	2017 7	2018 8	2019 9	2020 <i>10</i>	2021	2022 <i>12</i>	2023 <i>13</i>	2024 <i>14</i>	2025 15	2026	2027 17	2028 18	2029 19	2030 20	2031	2032	2033 23	2034	2035	2036	2037 27	2038	2039 29	2040 30
42 1 43 2 44 3	Carbon	\$ Per tonne		\$20.00	\$25.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00		\$30.00	\$30.00			\$30.00	++ + + + + + + + + + + + + + + + + + + +	\$30.00	\$30.00	\$30.00	\$30.00		\$30.00	\$30.00			\$30.00	\$30.00		\$30.00	\$30.00	\$30.00	\$30.00	\$30.00
44 3 45 4	Carbon GDP Deflator	\$ Per GJ		\$0.9976 1.00	\$1.2470 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00		\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00	\$1.4964 1.00
45 4 46 5 47 6	Carbon (Real) Net Present Value -2010			\$1.00	\$1.25	\$1.50 \$3.23	\$1.50 \$4.37	\$1.50 \$5.43	\$1.50 \$6.42	\$1.50 \$7.34	\$1.50 \$8.20	\$1.50 \$9.00	\$1.50 \$9.75	+ - 10 0	\$1.50	\$1.50 \$11.72	\$1.50 \$12.29	\$1.50 \$12.82	\$1.50 \$13.31	\$1.50 \$13.78	\$1.50 \$14.21	\$1.50 \$14.61	\$1.50 \$14.99	\$1.50 \$15.34	+	\$1.50 \$15.97	\$1.50 \$16.26	\$1.50 \$16.52		\$1.50 \$17.00	\$1.50 \$17.22	\$1.50 \$17.42	\$1.50 \$17.61	\$1.50 \$17.79
48 7	Net Present Value -2011				φ2.02	\$2.47	\$3.68	\$4.82	\$5.88	\$6.87	\$7.79	\$8.65	\$9.45			\$11.56	+	\$12.74	\$13.27	\$13.76	\$14.23		\$15.06	\$15.44			\$16.42	\$16.71		\$17.00	\$17.45	\$17.67	\$17.87	\$18.06
49 8 50	Net Present Value -2012						\$2.70	\$3.92	\$5.05	\$6.11	\$7.10	\$8.02	\$8.88	\$9.69	\$10.44	\$11.14	\$11.79	\$12.40	\$12.97	\$13.50	\$14.00	\$14.46	\$14.89	\$15.29	\$15.67	\$16.02	\$16.35	\$16.65	\$16.94	\$17.21	\$17.45	\$17.69	\$17.90	\$18.10
51	Discount Rate (real) ¹			+ +																														
53	TERASEN GAS Rate of Inflation																																	
54	T TG	GI 7.15% VI 6.89%																																
56	BC HYDRO																																	
57 58	Rate of Inflation BC Hyd																																	
59	Custom	er 6.00%																																
60 61	Footnote 1: Source LR 0705.	31																																
62																																		
64																																		
65																																		
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Fortis BC			only enter	r in boxes marl	ked in blue	9
Commercial			•			
NEW						
Measure Data for Solar Co	m					
Wiedsure Data for Solar ee	////					
			Utility Incentive to			
PER MEASURE			the participant	partner incentive		
Incremental Cost		2				
Total Incentive	•					
Participant	\$ 54,77	2				
Annual Impact Per Measure	76.4	CI		A		
Energy Savings per installation	76.4 0%	GJ		Average Annnual Energy Savi	ngs per Measure	
Free Rider Rate / Net-to-Gross Alternate Energy Impact	0%	1.00 GJ	0	Net-to-Gross kWh		
		kW/a	U	NV∛II		
Alternate Capacity Impact Measure Lifetime	25	Years	Estimated lifespan of	0001170		
Measure Lifetime	25		Estimated lifespan of m	Casule		
ANNUAL ACTIVITY	2040 NR		2010	2011	2012	Evelopetory Notos
	<u>2010 NPV</u>	Total	2010	<u>2011</u>	2012	Explanatory Notes
Number of Installations			•			
Impact		1 1	0	1		Estimated Participatation
Impact	.	71		70		
Gross Energy Savings (GJ)		71 76		76	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)		71 76		76	0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)		0 0	0 0	0	0	Other Utility Billed energy impact
Alternate Capacity Impact (Increase) (kW/a)	\$0.0	- 0				Other Utility Billed capacity impact
Benefit Cost Summary						
	<u>2010 NPV</u>	<u>\$ Total</u>	<u>2010</u>	<u>2011</u>	2012	_
Avoided Revenue Requirements						
PV \$ per GJ			\$120.87	\$125.59	\$129.77	7
Energy Purchases	\$ 9,59	8 <u>\$ 9,598</u>	<u>\$</u>	\$ 9,598	<u>\$</u> -	<u>-</u>
Utility Program Costs						_
DSM Incentives		\$-	\$-	\$ -	\$-	
Administration		\$ 3,750	\$ -	\$ 3,750		
Subtotal	\$ 3,50	0 \$ 3,750	\$ -	\$ 3,750	\$ -	
Partner Program Costs				-, ••	-	-
DSM Incentives		\$-	\$ -	\$-	\$-	
Administration		\$ -	\$ -	\$ -	\$ -	
Subtotal	\$ -	<u> </u>	\$ -	\$ -	\$ -	
Participants' Net Costs	· ·	· ·	Ŷ	Ŧ	¥	-
Incremental Cost		\$ 54,772	Ś -	\$ 54,772	Ś -	
Subtotal	\$ 51,11			\$ 54,772		-
Alternate Savings - Net	\$ 51,11	/ > 54,//2	ې -	ې 54,//2	ې -	-
Energy (Purchases)		ć	Ś -	¢	Ś -	\$1.534 PV \$ per kWh
		ې - د	ې - ذ	ې - د	ې - د	91.534 PV \$ per kwn PV\$ per kW/a
Capacity (Purchases)		<u>,</u>	ې -	<u>, -</u>	<u>ې -</u>	
Subtotal	\$ -	Ş -	<u>ې -</u>	\$ -	<u>\$</u> -	
Total Resource Net Benefit (Cost)	\$ (45,01		\$ -	\$ (48,924)		Avoided Revenue Requirement less Utility less Partners less Participant
Utility Levelized Cost per GJ (Lifetime)	\$ 66.	0	\$ -	\$ 66.6	ş -	Informational (for comparison with supply options)