Terasen Gas

Tom A. Loski
Chief Regulatory Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7464
Cell: (604) 250-2722
Fax: (604) 576-7074
Email: tom.loski@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

July 11, 2008

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively the "Companies" or the "Terasen Utilities")
Energy Efficiency and Conservation Programs Application - Project No. 3698512

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 1

On May 28, 2008, the Companies filed the Application as referenced above. In accordance with Commission Order No. G-102-08 setting out the Preliminary Regulatory Timetable for the Application, the Terasen Utilities respectfully submit the attached response to BCUC IR No. 1.

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

Yours very truly,

On behalf of the TERASEN UTILITIES

Original signed

Tom A. Loski

Attachment

cc (e-mail only): Registered Parties

1.0 Reference: Exhibit B-1, Executive Summary, Present Value of Savings, p. E-6

1.1 It is stated that the present value from energy efficiency is estimated to be almost 10 million GJ over the lives of the various measures proposed. Please provide the annual savings in GJ for each measure over its lifetime and show how the present value of 10 million GJ was calculated.

Response:

Included in Attachment 1.1 is the live electronic workbook. Discount rates used were 6.75% for TGI and 6.38% for TGVI. These rates are consistent with the rates used in the 2007 MX test for the respective company. The 2007 rates have been used as that was the best information available when the initial analysis for the EEC application was commenced. These are on a pre-tax basis.

1.2 It is stated the portfolio has a net financial benefit to customers of $165.1 million. Please define the term "net financial benefit to customers" and show the annual net benefit by program detailing the components of the net benefit for each program.

Response:

"Net financial benefit to customers" refers to the Total Resource Benefit, as discussed in Section 6.13 of the Application. The $165.1 million is the Total Resource Benefit excluding free rider effects. Net benefit by program area can be found in Appendix 11 of the Application. Net benefit by measure can be found in the response to BCUC IR 1.56.2.

2.0 Reference: Exhibit B-1, Executive Summary, Portfolio TRC, p. E-7

2.1 TGI and TGVI (collectively "Terasen" or "the Companies") state that the overall portfolio must maintain a TRC of 1.0 or higher but that individual programs may have a TRC of less than 1.0 if the purpose is to encourage market penetration for a new technology and economies of scale. Please confirm that "overall EEC portfolio" means all of the programs combined and that portfolio does not refer to programs targeted to a particular sector or customer class.

Response:

"Overall EEC portfolio" means the entire slate of EEC activity outlined in the Application including:

- Residential Energy Efficiency
- Commercial Energy Efficiency
- Residential Fuel Switching
- Conservation Education and Outreach
- Joint Initiatives
- Trade Relations
- 2009 Conservation Potential Review
- Innovative Technologies, NGV and Measurement

2.2 Are the Companies making any proposal with respect to threshold values for the Utility Test or RIM?

Response:

No, the Companies are not making any proposal with respect to threshold values for the Utility Cost Test, or RIM. The following is excerpted from page 22 of the Summit Blue report filed in response to BCUC IR 1.85.1:

> *"For the 15 jurisdictions investigated for this project, the most important benefit-cost analysis tests are TRC and societal tests."*

The Companies believe that a portfolio-level TRC approach, as described in the Application, is the appropriate approach.

2.3 How will the Companies decide that a technology has a longer term potential for a higher TRC?

Response:

For new technologies, the Companies would rely on information from industry groups, from suppliers, from consumer surveys, and from other utilities to determine whether a new technology has the potential for market penetration levels needed to bring the TRC to a positive ratio. The Companies' proposed approach to evaluating new technologies is reflected in the following excerpt from a study done by the Seeline Group for the Ontario Power Authority in December 2005.

(http://www.conservationbureau.on.ca/Storage/12/1727_OPA_Technology_Study_12_08_Final.pdf)

> *"Companies may wish to design programs around technologies that have a negative TRC as a way of pilot testing the market and determining market response. Given the right market conditions, technologies will move from a negative TRC result to a positive one. (There are many examples including the compact fluorescent bulb, condensing furnaces, horizontal clothes washers etc.) Programs that attempt to accelerate leading edge technologies that may not be cost effective now could generate significant cost effective savings in the future; and, cost effectiveness analysis represents a static assessment in a dynamic marketplace. Savings and costs estimates tend to change over time as base case equipment improves, new information is collected and markets respond to supply and demand. Avoided costs also tend to be volatile. As such, any TRC results should be considered as part of a more strategic understanding of the market."*

2.4 Have the Companies calculated results based on the Societal Test? Would Terasen agree that if GHG emissions are included as the only societal cost, from a BC perspective, conservation programs would show Societal Test results higher than the TRC and fuel switching programs (to increase natural gas use) would show Societal Test results lower than the TRC? If not, why not?

Response:

The Companies have not calculated results based on the Societal Test.

The Companies included the avoided Carbon Tax in the participant benefits, as can be noted in Appendices 11A and 11B, and in doing so have attempted to monetize the changes in GHG emissions from conservation and fuel switching programs. The Companies believe that it would not be appropriate to include GHG emissions as the only societal cost in a Societal Test. To be of value, the Societal Test should incorporate not only GHG emissions, but also other societal impacts, such as impacts on land use, on First Nations, on air emissions/quality, on energy transmission requirements, on energy security and on provincial revenues from the production of natural gas. Since no work has been done on monetizing these other societal impacts for British Columbia, the Companies cannot comment on whether a Societal test would show results higher or lower than a TRC test.

The majority of fuel switching activity the Companies are proposing in the Application is for TGVI. Fuel switching expenditures for TGVI are proposed to be a total of $2.367 million vs. $1.329 million for TGI. The breakdown of fuel switching activities proposed for TGI and TGVI can be found in Table 6.4 on page 63 of the Application. It should be noted that the fuel switching activity for TGVI includes heating retrofits. These would be aimed at British Columbians in TGVI service area that currently use oil or propane as a heating energy source. Even in the absence of any work on determining and monetizing the appropriate inputs to a Societal test, in the case of oil or propane fuel switching to natural gas, it stands to reason that the Societal test would show a result higher than the TRC, because of reductions in various inputs to a Societal test, including GHG emissions, criteria air contaminants and emissions from the transportation of oil and propane to a participant's home. Moreover, the Companies believe that substituting the direct end use of natural gas for electric space and water heating makes more of that "green" electric power available for export to displace electricity generated elsewhere in the western interconnection through the less efficient combustion of natural gas or coal. This would provide a net reduction of GHG emissions in the region from electric-to-gas fuel switching in British Columbia, and would presumably increase the results of a Societal Test that considers GHG emissions from a regional perspective. Please see BCUC IR 1.23.4.

3.0 Reference: Exhibit B-1, Executive Summary, Free Riders, p. E-8

3.1 Does the California Standard Practice Manual indicate whether an adjustment for free riders is necessary?

Response:

There are a number of Information Requests related to free riders; this is a consolidated response to the following IRs: BCUC IR No. 1, Questions 3.1, 3.2, 3.3., 3.4, 46.2.3, 46.5, 49.3 and 49.4.

As noted on page 85 to 87 of the Application, the Companies propose that the requirement to net out energy savings resulting from the participation of "free riders" be eliminated from the cost-benefit analyses for EEC programs in British Columbia.

Free riders are one of the most-debated aspects of DSM cost-benefit tests as they are challenging to establish. Other inputs are less contentious:

- Participation rates are forecast at the outset of a program and can be modified as the program progresses and replaced with actual participant numbers.
- Energy savings can be estimated with engineering calculations and billing analysis.
- Expenditures for incentives and program administration and promotions are forecast at the outset of a program, and can be modified as the program progress and replaced with actual expenditures

Estimating free rider rates, on the other hand, is more of an art than a science. One of the key elements of free rider estimation is post-participation surveying of participants as to their motivation for participating in a program. Responses to survey questions about program participation motivation are subjective, yet those responses are used as one of the key inputs to free rider rates, which are then used in an objective analysis: the cost benefit tests. The Companies believe that free rider rates are notional because of their subjectivity, and using them in objective analysis such as the DSM cost-benefit tests along with the other "hard" inputs to the tests, which are more easily quantified, diminishes the value of those tests.

Free rider rates can take on greater significance as an input to cost-benefit tests, and hence become more contentious, if utilities have in place a DSM financial incentive that is based upon program net savings and Total Resource Cost, both of which are somewhat affected by assumptions about free riders. In such cases, stakeholders are interested in whether utilities are underestimating free riders which would then result in a higher net-to-gross ratio, higher program savings, a higher TRC and presumably a higher incentive. This is reflected in the studies of other jurisdictions and authorities (and in particular, the California Standard Practice Manual), discussed in detail below. It should be noted that the Companies are not proposing that they receive a DSM incentive based upon net-to-gross ratios and TRC; rather the Companies are proposing that EEC expenditures be treated as equivalent to capital.

It should be further noted that, based on the portfolio proposed in this Application, the difference between including free riders and excluding free riders is small: including free riders changes the TRC ratio from 3.1% to 2.9%, a change of 0.2%, and the overall portfolio level TRC for the proposed portfolio of EEC activity for the Terasen Utilities is still well above 1.0, the proposed TRC threshold.

Program evaluations that attempt to quantify free rider ratios are more costly than those that make no attempt to quantify free rider ratios due to the need to conduct surveys. Yet free rider ratios only have a very small impact on the portfolio-level TRC for the portfolio of EEC activities proposed by the Companies. Eliminating the need to quantify free rider ratios in program evaluations would reduce evaluation costs, providing better value to ratepayers.

It is the Companies' view as expressed on page 86 of the Application that it is the energy consumption reduction outcome that matters, not the way in which it was achieved. Government's GHG reduction goals are absolute, with a GHG reduction target of 33% below 2007 levels by 2020 and 80% below 2007 levels by 2050. These GHG reduction goals make no mention of net-to-gross ratios – in fact they could be considered "gross" GHG reduction goals, and presumably it is gross energy savings that will be counted towards achieving those goals. It makes sense to align gross estimations of energy savings from utility DSM programs with government's gross GHG reduction goals.

Studies and Reports on Free Rider Ratios

There is a significant body of work on free rider ratios. Some of it is discussed below.

The California Measurement Advisory Council has a searchable database of evaluation reports (http://www.calmac.org/search.asp), as does the Consortium for Energy Efficiency's Market Assessment and Program Evaluation Clearinghouse (http://www.cee1.org/search/search.php).

Depending on their regulatory environment, many utilities conduct evaluation studies that examine free rider and in some cases, free driver rates for their particular programs. These studies examine the effectiveness and impacts of a particular program.

It should be noted that free riders and free drivers are often discussed together because they are factors in program impact evaluations. These factors are seldom studied in isolation because they are just particular aspects of evaluation and can only really be understood together with the other factors. The summary below provides a brief overview of North American independent studies that analyze and quantify the free driver and free rider effects; key highlights and definitions are also included.

One authoritative reference on this subject is the Model Energy Efficiency Program Impact Evaluation Guide,1 published by a U.S. organization, the National Action Plan for

[1] http://www.epa.gov/cleanenergy/documents/evaluation_guide.pdf

Energy Efficiency. Chapter 5 examines program impact evaluation and offers the following definitions:

- Free rider: A program participant who would have implemented the program measure or practice in the absence of the program. Free riders can be total, partial, or deferred.
- Free driver: A non-participant who has adopted a particular efficiency measure or practice as a result of the evaluated program (the effects of free drivers are included in non-participant spillover effects).
- Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.
- Net savings: The total change in load that is attributable to an energy efficiency program. This change in load may include, implicitly or explicitly, the effects of free drivers, free riders, energy efficiency standards, changes in the level of energy service, and other causes of changes in energy consumption or demand.
- Gross savings: The change in energy consumption and/or demand that results directly from program-related actions taken by participants in an efficiency program, regardless of why they participated.
- Net-to-gross ratio (NTGR): A factor representing net program savings divided by gross program savings that is applied to gross program impacts to convert them into net program load impacts.
- Market transformation: A reduction in market barriers resulting from a market intervention, as evidenced by a set of market effects, that lasts after the intervention has been withdrawn, reduced, or changed.

The Guide later also offers this caveat regarding the accuracy of measuring free ridership and spillover:

> *It should be noted that the analysis of spillover and free ridership is complicated by "market noise." When a market is filled with many implementers offering similar programs under different names, with different incentive structures and marketing methods, it is difficult to estimate any particular program's influence. Identification of non-participants may also be difficult, since customers may not be able to discern between the various programs operating in the marketplace and may not accurately recall how programs may have influenced their decision processes or even remember the program in which they participated.*

There are several additional studies that examine free riders and free drivers. The California Evaluation Framework[2] provides some detailed guidance on dealing with free ridership, spillover, and net-to-gross ratios. Although some of the "guidance" in the Framework is required in California, many of their protocols can be considered best practice for program impact evaluators. On page 133 a discussion of impact evaluation begins and discusses reasons for performing impact evaluations, evaluation methods, and econometric methods of estimating net savings impacts. Chapter 10, which begins on page 145, discusses methods for assessing market transformation effects.

PA Consultants performed a study for some utilities in the Northeast who wanted to have a uniform method for measuring free ridership and spillover effects: "Standardized Methods for Free Ridership and Spillover Evaluation[3]." The report is useful in its attempt to create a standard, uniform practice for impact evaluations. The relative complexity of such a practice is apparent in this report and demonstrates that the value of having accurate net-to-gross ratios is sometimes not worth the effort and cost of measuring it.

Recently, some have begun to question the value of including free rider rates, especially in the context of utility programs aimed at market transformation. Rafael Friedman's article, "Maximizing Societal Uptake of Energy Efficiency in the New Millennium: Time for Net-to-Gross to Get Out of the Way?" argues that using net-to-gross ratios in calculating the cost effectiveness of an energy efficiency program creates a barrier and a disincentive to utilities to run more programs and more broad-sweeping and market transformative programs. One of the key points made by Mr. Friedman is that *"both spillover and free ridership are becoming much harder to determine as the context becomes one that embraces energy efficiency…"* and certainly it could be argued that the context in British Columbia is becoming one that embraces energy efficiency. The article is attached.

Other Jurisdictions

The table below summarizes the practice of other jurisdictions as it relates to adjusting for free rider ratios. The material following the table provides some further information.

---

[2] http://www.cee1.org/eval/CEF.pdf
[3] http://www.cee1.org/eval/db_pdf/297.pdf

Company Name	Adjusts for Free Riders (Yes/No)
Pacific Gas and Electric Company ("PG&E")	Yes
Manitoba Hydro	Yes
Southern California Gas Company ("SoCal Gas")	Yes
BC Hydro and Power Authority ("BC Hydro")	Yes
FortisBC	No
Northwest Natural Gas Company ("NW Natural")	Yes
Union Gas	Yes
Enbridge Gas Distribution ("Enbridge")	Yes
Gaz Metro Limited Partnership ("Gaz Metro")	Yes
Puget Sound Energy ("PSE")	No
SaskEnergy	No
ACTO Gas	No

Please note that the Government of British Columbia, in their LiveSmart BC program, did not make an adjustment for free riders.[4]

<u>California</u>

The California Standard Practice Manual states:

> *"The development and treatment of load impact estimates should distinguish between gross (i.e. impacts expected from the installation of a particular device, measure, appliance) and net (impacts adjusted to account for what would have happened anyway, and therefore not attributable to the program). Load impacts for the Participants test should be based on gross, whereas for all other tests, the use of net is appropriate. Gross and net program impact considerations should be applied to all types of demand side management programs, though in some cases there may be no difference between gross and net."*

In California, the CPUC has ruled that savings associated with free riders should not be considered a benefit in calculating the effectiveness of a program. Conversely, rebate paid to free riders should be included as a program cost but administrative costs associated with free riders should not be counted:

[4] Source: telephone conversation Sarah Smith Terasen Gas/Erik Kaye MEMPR, July 10, 2008

> *"In the context of energy efficiency, "free riders" are those program participants who would have undertaken the energy efficiency activity in the absence of the program. We adjust program savings to remove the effect of free riders because their participation would have happened anyway, and therefore the savings associated with their actions cannot be considered a benefit of the program. Today we clarify that participant costs should also be adjusted to account for free riders, unless those costs represent program expenditures (utility revenue requirements)[5]."*

Ontario

The role of free riders in the TRC calculation is outlined in Section 2.1 of the Ontario Energy Board's TRC Guide[6].

> *"Costs and benefits associated with free ridership should be assessed as part of the TRC analysis. In determining overall savings, these participants are excluded from the benefits attributed to the program. The equipment costs associated with these participants is similarly excluded from cost side of the equation. However, it should be noted that all program costs associated with free riders must be included in the analysis. As such, programs that have high free ridership are self-evident in the marketplace (i.e. they do not rely on a LDC promotion) and therefore are less cost effective for the LDC to pursue since the program costs are included in the TRC calculation while the benefits are not. Free rider estimates are established through market studies and initial values have been provided in the Assumptions and Measures List.[7]"*

It should be noted that the OEB directed that further work should be done on determining realistic free ridership levels for custom programs. Free ridership levels are also factored into the LRAM and SSM calculations.

One key point is that the California Standard Practice Manual was first developed for the California Utilities and that the CPUC and OEB both govern gas utilities that have an incentive. The net-to-gross guidelines set out in the material above apply to jurisdictions where the utilities receive an incentive based upon energy savings/TRC. The Terasen Utilities are not proposing that they receive an incentive for EEC expenditure; rather the Companies propose that EEC expenditure be capitalized. One of the advantages that the Companies' financial treatment provides is that is removes the need for the complexity and expense associated with finessing TRC results for notional free rider rates.

In conclusion, the Companies believe that free rider rates should be eliminated from the cost-benefit analysis required by BC utilities.

---

[5] http://docs.cpuc.ca.gov/published/FINAL_DECISION/73172-15.htm#P1161_304097
[6] http://www.oeb.gov.on.ca/documents/cases/RP-2004-0203/cdm_trcguide_021006.pdf

3.2 The Companies state the cost-benefit analysis is based on gross rather than net savings. Please explain the value of an analysis based on gross savings.

3.2.1 The Companies state that using the net figure may lead to results that run counter to the objectives of energy policies. Given the Energy Plan's focus on cost effectiveness, please explain how the policies' objectives will be subverted by using net savings.

Response:

Please refer to the response to BCUC IR 1.3.1.

3.3 Free ridership is excluded from the analysis due in part to uncertainties around free ridership rates. Do the Companies have any evidence that forecasts of free ridership are any more or less uncertain than other forecasts associated with DSM programs, such as penetration rates and energy savings?

Response:

Please refer to the response to BCUC IR 1.3.1.

3.4 What is the policy of other jurisdictions surveyed by Terasen (e.g. Ontario) with respect to adjustments for free riders?

Response:

Please refer to the response to BCUC IR 1.3.1.

3.5 The 2007 DSM Report in Appendix 2 at page 8 shows free rider rates for TGI DSM programs ranging from 50% to 0% for the Destination Conservation program? How were those free ridership percentages estimated? Is it Terasen's view that the percentages included in the 2007 DSM report are too inaccurate to be considered reliable?

Response:

As noted in TGI's "2006 Annual Review and Mid Term Assessment Review 2006 Demand Side Management ("DSM") Portfolio Report ", filed June 5, 2007:

> *"Free rider levels were anticipated and forecast at the time of program development, most of which were developed in 2005. Terasen Gas will be undertaking program evaluations on the Energy Star Heating Upgrade, Residential New Construction and Efficient Boiler Programs in 2007 and a key aspect of the evaluation of these programs will be analysis of free rider levels."*

The Energy Star Heating System Upgrade Evaluation Report has since been completed and has been filed in response to BCUC IR 1.71.2. That report indicated a free rider rate of 43%, thus the estimate of 50% free riders in the 2007 DSM Report is conservative. An evaluation study is currently underway for the Commercial Energy Utilization Advisory program – the results are anticipated at the end of August. The free rider rate for Destination Conservation is estimated at zero based the following: TGI pays for the school's first year in the Destination Conservation program – this is used by the contractor as the "sales tool" to entice schools to participate. Therefore all the participating schools in Destination Conservation are participating as a result of TGI covering the first year of the Destination Conservation program. The TGI Efficient Boiler Program and Residential New Construction Energy Star Heating Program free rider rates were estimated by the program designers at the time of program development, based on the Company's best judgment. Evaluations on these programs have not yet been completed; the Company plans to launch an evaluation of the Efficient Boiler Program before the end of 2008. The free rider rates used by TGI in the 2007 Annual Review were based on the information and resources available at the time that the Review was written.

It is the Companies' view that free rider rates are notional and more of an art than a science. The Companies used the best available data to determine free rider rates for the 2007 programs. The Companies believe that their estimates of free rider rates are no more or less reliable than the estimates of free rider rates developed by other utilities.

4.0 Reference: Exhibit B-1, Executive Summary, Future Regulations, p. E-8

4.1 The Companies propose to include benefits from future regulations in the TRC ratio calculation and state that "The TRC ratios referenced in the Application have been derived using this approach."

Please recalculate Table 4.1 (page 45), Table 6.13 (page 85) and Table 7.2 (page 99) excluding the benefits included from future regulations. For each row in each table please explain the nature and timing of the relevant regulation. Please state the year to which the data in Table 7.2 refers.

Response:

The last sentence is mis-worded; attribution of savings from regulation was **not** included in the cost-benefit calculations in this Application, as noted on page 87. Tables 4.1, 6.13 and 6.13a, and 7.2 do **not** include any energy savings from the introduction of regulation.

5.0 Reference: Exhibit B-1, Section 1.3 Market, Market Conditions, p. 7

5.1 The Companies state there are new market conditions. Does this refer to the increase in the price of the commodity or changes in government objectives?

Response:

The reference to "new market conditions" refers to both increased energy prices as well as changes to government policy, as outlined in sections 3.3 and 7.3 of the Application.

5.2 Since market prices have increased sharply, are customers currently more incented or less incented to undertake efficiency measures even in the absence of utility funded programs?

Response:

The Companies have not conducted research that would indicate whether customers are more incented or less incented to undertake efficiency measures in the absence of utility-funded programs. However, all other things being equal, the Companies expect that higher prices will tend to encourage conservation more than lower prices.

6.0 Reference: Exhibit B-1, Section 2, Expenditures, p. 15

6.1 The Companies state that 2010 expenditures would not exceed $56.6 million unless otherwise approved by the Commission. Absent such approval, how would the Companies ration expenditures were demand to exceed $56.6 million?

<u>Response:</u>

Absent Commission approval for expenditure over $56.6 million, the Companies would allocate available funds based on Total Resource Cost results, while ensuring that all Residential and Commercial customers were able to access Energy Efficiency and Conservation activity, based on the Companies' own judgment and input from the Stakeholder Group. The Stakeholder Group is outlined in section 6.14.2. However, if demand from the marketplace for EEC activity by the Terasen Utilities were strong enough that the entire budget of $56.6 million was to be consumed prior to 2010, the Companies would propose to bring forth another Application prior to the timeline outlined in the Application.

7.0 Reference: Exhibit B-1, Section 2, Free Riders and Government Goals, p. 16

7.1 Please provide all documentation that supports the statement that "…energy and emissions reduction goals of the government are absolute goals and do not include free ridership effects." (emphasis added)

Response:

Please see the 2007 and 2008 Speeches from the Throne attached in the Application as Appendix 5. The following is excerpted from page 11 of the 2008 Throne Speech:

> *"The Greenhouse Gas Reduction Targets Act now requires us to reduce greenhouse gas emissions by 33 per cent from 2007 levels by 2020, and by 80 per cent below 2007 levels by 2050."*

The same commitment was made in the 2007 Throne Speech, on page 14. These are absolute targets; no mention is made of net-to-gross ratios in these targets as announced by government and subsequently included in Bill 44, the 2007 Greenhouse Gas Reduction Targets Act.

7.2 The Application states that for programs aimed at preparing the market place for introduction of regulation of maximum efficiency levels for a piece of equipment, a building, or an energy system, savings associated with the implementation of the applicable regulation will be included in the benefits of the program.

7.2.1 What types of programs would Terasen consider to be "…aimed at preparing the market place for introduction of regulation of maximum efficiency levels for a piece of equipment, a building, or an energy system…"?

Response:

Please note that the Application states that for programs aimed at preparing the market place for the introduction of minimum efficiency levels, rather than maximum efficiency levels, as the question is written. The types of programs that the Terasen Utilities would consider to be *"…aimed at preparing the marketplace for introduction of minimum efficiency levels for a piece of equipment, a building or an energy system…"* would be those programs for equipment, buildings or energy systems where government at the municipal, provincial or federal level has announced their intention to introduce regulation for minimum efficiencies, which they generally do well in advance of implementing that regulation.

7.2.2 To the extent that such programs were undertaken with one or more other parties (e.g. other utilities, trades associations, governments) is Terasen proposing that all of the benefits of the regulations be allocated to the Terasen programs? If not, how would it choose to allocate the benefits?

Response:

For any programs that are undertaken with partners, the Companies would propose that benefits should be allocated based on the percentage of financial contribution by each partner.

8.0 Reference: Exhibit B-1, Section 3.2.1, TGI EEC Initiatives, p. 22 and Appendix 2

The Application notes that in 1997, the Commission endorsed a mechanism to pursue DSM resources through the DSM Achievement Incentive, and states that the Companies have not to date submitted a protocol for measuring DSM savings and TRC benefits for collecting a DSM incentive, and therefore has not to date applied to receive the DSM Achievement Incentive.

Appendix 2 of the Application shows in the 2007 DSM Report at page 8 a table showing DSM results and "TRC Net Benefits".

8.1 If Terasen had not submitted a protocol for measuring DSM savings and TRC benefits, what was the basis for the results in the 2007 DSM Report?

Response:

To clarify, the Companies have not submitted a protocol related to the issue of claiming an incentive based on measured DSM savings which then relate to a TRC. Presumably such as incentive would be based on reaching a certain TRC or energy savings threshold and it is a protocol related to claiming an incentive that has not been submitted. Results in the 2007 Annual Report were reported using the same methodology as in years previous.

Energy savings estimates in the 2007 DSM report were established as follows:

- Energy Star Heating System Upgrade – 2003 Residential DSM Campaign Evaluation – filed in response to BCUC IR 1.71.1
- Residential New Construction Energy Star Heating Program – estimated at program design
- Efficient Boiler Program – based on aggregate of savings for program participants for the year
- Destination Conservation – based on 2007 study of Abbotsford School District participation in DC
- Commercial Energy Utilization Advisory – based on program design.

TRC benefits included in the report were calculated using a model developed for TGI by Willis Energy.

8.2 Is Terasen submitting a protocol for measuring DSM savings and TRC benefits in this Application? If so, please identify where in the Application it is discussed and summarize the specific proposals for necessary measurement activities (for example, monitoring and verification, estimation of persistence of benefits).

Response:

The Companies are not submitting a protocol in this Application, other than proposals around the portfolio approach, and the treatment of free riders and attribution from regulation in section 6.13 of the Application. Rather the Companies are hopeful that the work of the "Measurement, Analysis and Reporting Task Force", of which the Companies are a member, that is being formed as a sub-group of the British Columbia Partnership for Energy Conservation and Efficiency (or BCPECE, an initiative being led by the Ministry of Energy Mines and Petroleum Resources) will address this issue. The goal of the task force is to bring key government, utility and regulator representatives together to devise a common protocol for the reporting on energy conservation, energy efficiency and DSM programs and results.

9.0 Reference: Exhibit B-1, Section 3.2 History of Demand Side Management Programs, pp. 22-25

Table 3.2.1 TGI Historical Summary DSM Programs

On page 24 it shows Table 3.2.1 - TGI Historical Summary DSM Programs shows a table of programs. The Energy Star Heating System Upgrade Program in 2007 estimates 13.8 GJ savings per participant per year.

9.1 Please show the calculation the 13.8 GJ savings for the furnace and boiler separately along with the base equipment and technologies.

Response:

The calculation is based upon the findings of the 2003 Energy Star Heating Upgrade Program Evaluation, filed in response to BCUC IR 1.71.1. The information can be found on pages 64-66 of the report. The billing analysis found savings of 12.6 GJ going from a mid efficiency furnace to an Energy Star furnace. However, it also found that, on average, the program induced participants to install the new furnace 2.3 years earlier than they otherwise would have. For these 2.3 years, the energy savings are an additional 8.6 GJ, which is the difference between a standard and a mid efficiency furnace. The "blended" savings for a furnace over its life is 12.6 GJ X 25 years, plus 8.6 GJ X 2.3 or 335 GJ. On an annual basis this is 335 GJ / 25 years or 13.4 GJ per year. At some time in the past, the Companies made a decision to adjust the 13.4 GJ to 13.8 GJ, probably due to the increasing efficiency of Energy Star furnace stock being installed over time (i.e. from 92 % AFUE to 93% AFUE, however supporting documentation for this change cannot be found. Compared to the calculations for the energy savings shown in the table in the response to BCUC IR 1.9.3.1, the estimate of 13.8 GJ/furnace used in the cost-benefit analysis and Annual Review may be conservative.

The estimate of energy savings will be updated upon finalization of the most recent Energy Star Heating Upgrade Evaluation Report. Phase 1 has been filed in response to BCUC IR 1.71.2.1, however the final report has not yet been received as noted in the response to BCUC IR 1.71.2.2.

9.2 Please show the calculation and assumptions of the TRC Cost Benefit Ratio for all the programs in Table 3.2.1 for 2007. Include the spreadsheet model.

Response:

Due to the commercial sensitivity of the information requested, the response to this question has been filed under separate cover in accordance with the BCUC Practice Directive pursuant to Section 13 of the *Administrative Tribunals Act* related to Confidential Filings. The Terasen Utilities have requested that the information be made accessible only to the Commission and to those authorized representatives of

Registered Intervenors who execute an undertaking, consistent with Attachment A to the BCUC Practice Directive, to hold the information confidential.

9.3 Assume a homeowner has an older 65% efficient furnace using 75 GJ per year that was at end of life, and the homeowner then had a choice of purchasing a mid-efficiency furnace at 80% AFUE or a 90% AFUE high-efficiency furnace.

9.3.1 What would be the installed cost including taxes of a mid-efficiency furnace to the homeowner? How much GJ of gas would the homeowner be expected to use?

Response:

For responses to BCUC IRs 1.9.3.1, 1.9.3.2 and 1.9.3.3, please see the table provided below.

These figures represent the sum of the cost of the furnace, contractor mark-up, installation charges, and any applicable taxes and permits.

	Installed cost ($) estimate including taxes	**Annual Gas consumption estimate (GJ)**	**Annual Volume Savings Over Older 65% efficient furnace (GJ)**	**Annual Volume Savings Over 80% mid efficiency furnace (GJ)**	**Payback of installing a 90% high efficiency furnace over 80% mid efficiency furnace (years)**
80% AFUE Mid Efficiency	$2,721	61	14		
90 % AFUE High Efficiency Furnace *	$3,477	54	21	7	7.8*

Source: Evaluation of Terasen Gas' 2005-07 Heating System Upgrade Program, Final Report, April 7, 2008, pg 28 & 60

GJ Calculation:

- 65% efficient furnace using 75 GJ/year
- 75 x .65 = 48.75 GJ heat load (75 – 48.75 = 26.25 GJ waste)
- **80% efficient furnace would use 48.75/0.8 = 60.9375 GJ/year**

GJ Calculation

- 65% efficient furnace using 75 GJ/year
- 75 x .65 = 48.75 GJ heat load (75 – 48.75 = 26.25 GJ waste)
- **90% efficient furnace would use 48.75/0.9 = 54.1667 GJ/year**

Payback Calculation (90% AFUE over 80% AFUE)

- Difference in fuel usage is 61 GJ – 54 GJ = 7 GJ/year
- Gas commodity Rate 1 Lower mainland as of July 1, 2008 = $13.834/GJ
- 7 GJ/year X $13.834/GJ = $96.81 /year savings in gas usage
- Cost of installed mid-efficiency (80%) furnace = $2721
- Cost of installed high efficiency (90%) furnace = $3477
- Incremental cost from 80% to 90% = ($3,477 – $2,721) = $756
- $756 / $96. 81/year = 7.8 years simple payback

*Note: the payback calculation for the installation of a 90% AFUE high efficiency furnace over an 80% AFUE mid efficiency furnace does not include the government rebates listed under section 9.3.2 as the net cost would result in an increase of $50 for the homeowner once they factor in the costs of the required energy audits. In order to qualify for the Eco Energy rebate of $300 for upgrading to a 90% AFUE high efficiency furnace, homeowners must be pre-qualified with an initial energy audit, follow through with energy upgrades in the next 18 months and have a follow up energy audit. The estimated cost for these audits are $250 each and there is a subsidy available through LiveSmart BC of $150 towards the cost of the initial audit. (2 Energy Audits @ $250 each = $500 - $150 subsidy (LiveSmart BC) = $350, less $300 Eco Energy rebate for 90% AFUE high efficiency furnaces = $50 increase in cost to the homeowner for installing a 90% high efficiency furnace).

9.3.2 What would be the installed cost including taxes of a 90% AFUE high-efficiency furnace to the homeowner? Cite the various incentives and sources of rebates available to the homeowner. How much GJ of gas would the homeowner be expected to use? What is the incremental payback in the years to the homeowner for opting for a high-efficiency furnace?

Response:

Please see the table above in response to BCUC IR 1.9.3.1 for installed costs, energy savings and payback.

The following government rebates are available to homeowners who pre-qualify with an initial energy audit, follow through with energy upgrades in the next 18 months and have a follow up energy audit.

- The Provincial LiveSmart BC program will provide a subsidy of $150 towards the cost of the initial energy audit; energy audits cost approximately $250 each before rebate.

- The Provincial LiveSmart BC program will pay $580 for an upgrade to a 92% efficient furnace with an ECM motor
- The Provincial LiveSmart BC program will pay $770 for an upgrade to a 95% efficient furnace with an ECM motor
- The Federal EcoEnergy program will pay a grant of $300 dollars for an upgrade to a 90% efficient furnace.
- The Federal EcoEnergy program will pay a grant of $500 dollars for an upgrade to a 92% efficient furnace with an ECM motor

Total government rebates available:

- $150 audit rebate
- 90% furnace rebates = $300
- 92% furnace rebates = $1080
- 95% furnace rebates = $1270

9.3.3 If the homeowner opted for the high-efficiency furnace what does TGI calculate to be the annual volume energy savings for this participant that would be included in the TRC test and RIM test?

Response:

Please refer to the response to BCUC IR 1.9.3.1.

9.3.4 How does TGI take into account in the TRC test the possibility that the homeowner with the new high-efficiency furnace may increase the homeowner's expected energy use by turning up the thermostat?

Response:

TGI has not taken into account the possibility that a homeowner with a new high-efficiency furnace may turn up the thermostat. The 2007 Furnace Upgrade Evaluation Report, filed in response to BCUC IR 1.71.2, found some evidence (page iv) that participants in the furnace upgrade program are maintaining their home temperatures a full degree lower than non-participants.

9.4 For 2006 and 2007, if available, please provide in a table the number of mid-efficiency and high efficiency gas furnaces sold in British Columbia. If possible estimate the percentage of installations for new construction compared to replacement of furnaces.

Response:

The mid and high efficiency furnace sold in BC for 2006 and 2007 are not available. The numbers for 2005 are available from Natural Resources Canada, and are shown below.

Residential Sector
British Columbia
Table 22: Single Detached Heating System Stock by Heating System Type

	1990	1998	1999	2000	2001	2002	2003	2004	2005
Total Single Detached Heating System Stock (thousands)	**751**	**892**	**899**	**907**	**918**	**930**	**942**	**951**	**969**
Heating System Stock by Heating System Type (thousands)									
Natural Gas – Normal Efficiency	374	350	347	344	340	336	331	326	321
Natural Gas – Medium Efficiency	8	71	77	84	88	97	103	108	113
Natural Gas – High Efficiency	17	51	55	59	62	70	78	84	94

Source:
http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tablestrends2/res_bc_22_e_2.cfm?attr=0

Statistics for sales for new construction versus retrofit are not kept. Sales to both markets are from the same distributors and they do not ask for the final destination of the sale.

10.0 Reference: Exhibit B-1, Section 3.2.1. EEC Initiatives, p. 23 - TGI DSM O&M

The Application on page 23 states regarding TGI: "Costs associated with advertising (including awareness programs), program promotion, program design, administration, research and evaluation are base O&M expenses of $1.624 million per year."

On page 93 in Table 7.1.2.1 – Current, Proposed, and Incremental EEC expenditures, by Utility the table box Total Proposed EEC Expenditures has TGI – Expense of $2.62 in 2008 & 2009 and $0.00 in 2010.

10.1 Please provide further information (description and cost breakdown) of these TGI O&M DSM expenses of $1.624 million per year for 2007. Are the 2007 actual costs different from budget?

Response:

Please see the table below. 2007 actual costs are close to budget and would have been slightly over-budget in the absence of partner contributions to O&M costs.

2007 O & M - TGI	Actuals	Budget
Labour	$306,468	
Employee expenses	$38,628	
Materials	$3,755	
Fees & Administration	$50,295	
Promotions and Advertizing	$966,098	
Consulting	$263,586	
Cost recoveries from partners	-$31,981	
Misc	$2,103	
Totals	**$1,598,952**	**$1,624,055**

10.2 Is TGI proposing that commencing in 2010 that the TGI O&M DSM incurred costs would no longer be expensed and instead added to the regulatory deferral account and amortized over 20 years? If so, explain why these operating costs should be capitalized.

Response:

Correct. Both TGI and TGVI are recommending that all costs associated with EEC activity be capitalized starting in 2010. Due to the TGI PBR Extended Settlement and TGVI RR Extended Settlement agreements that are in place for 2008 and 2009, TGI and TGVI have proposed that only the incremental spending for EEC activity for 2008 and 2009 be capitalized in the same manner as the 2010 expenditures.

TGI and TGVI have several reasons for recommending this financial treatment (capitalization) of costs associated with EEC activity.

From the perspective of ratepayers, capitalizing EEC expenditures helps to reduce rate impact to ratepayers by smoothing the increased expenditure over a period of time to which the benefit is received. Expensing the EEC expenditures may cause more rate volatility since the level of EEC expenditures may vary from year to year causing rate increases in some years and rate decreases in other years. Rate volatility may have unintended impacts on conservation and customer behaviour by causing temporary responses to the rate change without lasting conservation. Rate stability will permit customers to make more considered and lasting investments in conservation measures.

As indicated in the response to BCUC IR 43.1.1 and 42.3.4.5, when the time value of money is considered customers may be better off when the utility recovers the costs, including the utility's carrying cost, over an extended period of time rather than having to recover the cost in the year of expenditure. The present value of the revenue requirements from the rate base approach is lower for customers assuming customers have a time value of money preference based on a higher discount rate than the utility's after-tax cost of capital.

From an equity perspective, capitalization permits utilities to match the cost recovery period to the period over which benefits accrue to ratepayers. The benefits of the EEC programs contemplated in this Application are expected to persist on average for 22.5 years. If expensed, current customers will be paying the full cost of the EEC expenditures and future customers will receive the benefits of the DSM programs without having to bear the costs. Please refer to the response to BCUC IR 41.3.

The Commission's DSM Accounting Policy has recognized both the appropriateness of capitalizing DSM. The DSM Accounting Policy states, in part:

> *2. Deferred Costs Included in Rate Base and Earning a Return*
>
> *Costs incurred at different stages of program commercialization reflect varying degrees of uncertainty as to beneficial outcomes and shall be deferred according to the following criteria:*
>
> *(a) A significant or material, non-recurring cost shall be deferred and amortized using a rapid writeoff for the purpose of smoothing the impact on rates.*
>
> *(b) <u>Direct program costs, indirect administration costs and allocated overhead, shall be deferred according to the intent of section 3450 - Research and Development, of the Canadian Institute of Chartered Accountants, Accounting Recommendations Handbook. Generally speaking, those criteria treat research costs as expenses and treat as assets, those development costs that have a high probability of achieving net financial benefits.</u>*

3. Load Building by Fuel Substitution

Utilities engaged in strategic load building by fuel substitution may account for this <u>in the same manner as other DSM strategies</u> subject to Commission directions specific to that utility. Changes to this accounting policy may need to be made following a multi-utility review of the economic evaluation of fuel substitution. [Emphasis added.]

The fact that the DSM Accounting Policy provides for a range of acceptable amortization periods depending on the type of expenditure and an allowance for normal write-offs longer than 10 years, implicitly recognizes the need to match the cost recovery period to the period over which benefits accrue to ratepayers.

We note that Section 3450 Research and Development of the CICA Handbook, which is referred to in the DSM Accounting Policy, is being replaced with Section 3064 Goodwill and Intangible Assets, effective January 1, 2009. Section 3064 as it relates to Research and Development expenditures is substantially the same as previous section 3450, and includes the same approach to research (expense) and development (deferral) expenditures. Please refer to the responses to BCUC IRs 1.44.0 to 1.44.2 for further discussion of accounting guidance on EEC expenditures.

The financial treatment sought by the Companies in this Application is consistent with the financial treatment that has been approved for use by other BC utilities (in particular FortisBC and BC Hydro) regulated by the Commission, as set out on page 81 of the Application. Please see the responses to BCUC IR 42.1 and 43.2.4.2.

Section 60(1)(b) of the *Utilities Commission Act,* which requires the Commission to have due regard when setting rates that the utility is provided a fair and reasonable return on any expenditure made by it to reduce energy demand.

Capitalization is also consistent with the Energy Conservation and Efficiency Policies from "The BC Energy Plan: A Vision for Clean Energy Leadership". In particular, policy item #3 (Encourage utilities to purse cost effective and competitive demand side management opportunities) states (page 3), "Ministry will assess whether additional measures are needed to ensure appropriate incentives are in place to encourage investor owned utilities to identify and purse cost effective DSM programs". By capitalizing EEC expenditures the Companies are made indifferent between allocating funds to EEC programs that will potentially reduce infrastructure requirements and investing in infrastructure.

11.0 Reference: Exhibit B-1, Section 3.2.1, TGI EEC Initiatives, p. 25

The Application discusses the uncertainties around partner funding of DSM initiatives. Please confirm that the amounts requested for approval in the Application, assume no partner funding. If confirmed, and if partner funding is available, will the amounts to be spent by Terasen decrease? If the amounts requested assume some partner funding, please identify the amounts assumed and the programs to which those amounts are attached.

Response:

The amounts identified and request for approval in the Application are for the Companies' funded program areas only. The amount to be spent by the Companies will not decrease if partner funding becomes available. Partner funding could make wider program participation possible by increasing the total pool of dollars available for natural gas EEC activity. The exception is funding for electrical savings resulting from programs in the Commercial sector. Some assumptions about partner funding for incentives for electrical savings from Commercial programs are detailed in Tables 6.2b and 6.2c of the Application. If that partner funding for electrical savings should not materialize, the Companies would proceed with programs based on natural gas conservation activity alone.

12.0 Reference: Exhibit B-1, Section 3.2.2. EEC Initiatives, p. 26

The Application on page 26 states regarding TGVI: "Non-incentive expenses are approximately $500,000 annually, and are treated as O&M."

On page 93 in Table 7.1.2.1 – Current, Proposed, and Incremental EEC expenditures, by Utility the table box Total Proposed EEC Expenditures has TGVI – Expense of $0.50 in 2008 & 2009 and $0.00 in 2010.

12.1 Please provide further information (description and cost breakdown) of these TGVI O&M DSM expenses of $0.500 million per year for 2007. Are the 2007 actual costs different from budget?

Response:

Please see the table below. Actual costs are below budget due to the suspension of programs for TGVI pending the submission of this Application, which was noted in TGVI's November 2, 2007 response to BCUC IR No. 1, 2007 TGVI Settlement Update, Question 22.1, which is excerpted below:

"The DSM activity for 2007 was curtailed as a result of receiving Commission Order G-161-06, Appendix A, Section 2.2. The Commission ordered TGVI to "plan and evaluate its deferred incentive programs to include the standard RIM and participant cost tests". Previous to receiving the order referenced above, TGVI had evaluated its program based on the "Regulatory NPV" model. The DSM activity for TGVI is load-building activity. There are a number of weaknesses associated with the RIM and participant cost tests in evaluating load-building/fuel substitution programs as have traditionally existed in TGVI. Therefore the Company made a decision to put DSM programs for the Island on hold. It is the Company's intention to put forward a set of principles for planning and evaluating all programs, both conservation and load-building/fuel substitution programs, as well as making both types of program available to TGVI customers, in the Energy Efficiency and Conservation Application to be submitted prior to the end of 2007."

2007 O & M - TGVI	Actuals	Budget
Labour	$1,412	
Employee expenses	$2,211	
Materials	$527	
Fees & Administration	$8,111	
Promotions and Advertizing	$347,613	
Consulting	$9,325	
Misc	$7,976	
Totals	**$377,175**	**$497,000**

12.2 Is TGVI proposing that commencing in 2010 that the TGVI O&M DSM incurred costs would no longer be expensed and instead added to the regulatory deferral account and amortized over 20 years? If so, explain why these operating costs should be capitalized.

Response:

Yes. Please refer to the response to BCUC IR 1.10.2.

13.0 Reference: Exhibit B-1, Natural Gas Pricing and Rate Background, p. 29, and

Appendix 3, Rate History

"Prices for almost all forms of energy have been facing increased upward price pressures in recent years and natural gas is no exception. One of the Companies' primary reasons for submitting this Application is to help customers better manage their energy bills in the face of rising costs. EEC programs help customers to reduce their energy bills.

"Rates have more than doubled since the current level of DSM funding was established for the Terasen Utilities in 1997 (B-1, p. 29)"

13.1 What future prices for natural gas, over the life of the longest-duration proposed measure, has Terasen used as the basis for consumption and conservation estimates the Application? What is the source (or sources) of that (those) series? Please submit a table of the applicable future prices.

Response:

The table below details the avoided cost for natural gas used to generate the outcomes in Appendices 11A and 11B. It was developed by the Companies' Gas Supply group in 2007, and it was developed using a program called "Sendout". "Sendout" is a portfolio modeling tool used by Gas Supply to evaluate resources and determine the optimal mix of assets for the Annual Contracting Plan. The vendor is Ventyx (formerly New Energy Associates) in Atlanta.

Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
NATURAL GAS ($ Per GJ)										
Incremental Cost of Gas (nominal)	$10.43	$9.02	$8.76	$8.61	$8.08	$9.27	$7.96	$8.41	$9.52	$9.23
Years of Savings	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Incremental Cost of Gas (Real)	$10.43	$9.02	$8.76	$8.61	$8.08	$9.27	$7.96	$8.41	$9.52	$9.23
Net Present Value -2007		$19.45	$28.21	$36.82	$44.90	$54.17	$62.14	$70.54	$80.07	$89.30
Net Present Value -2008			$17.78	$26.39	$34.47	$43.74	$51.71	$60.12	$69.64	$78.87
Net Present Value -2009				$17.37	$25.45	$34.72	$42.68	$51.09	$60.62	$69.85

Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Incremental Cost of Gas (nominal)	$9.27	$9.37	$9.65	$10.00	$10.71	$10.31	$10.39	$10.55	$11.06	$10.96
Years of Savings	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
Incremental Cost of Gas (Real)	$9.27	$9.37	$9.65	$10.00	$10.71	$10.31	$10.39	$10.55	$11.06	$10.96
Net Present Value -2007	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30
Net Present Value -2008	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87
Net Present Value -2009	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85

Year	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Incremental Cost of Gas (nominal)	$11.49	$11.43	$11.66	$11.89	$11.89	$11.89	$11.89	$11.89	$11.89	$11.89
Years of Savings	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*
Incremental Cost of Gas (Real)	$11.49	$11.43	$11.66	$11.89	$11.89	$11.89	$11.89	$11.89	$11.89	$11.89
Net Present Value -2007	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30	$89.30
Net Present Value -2008	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87	$78.87
Net Present Value -2009	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85	$69.85

14.0 Reference: Exhibit B-1, Natural Gas Pricing and Rate Background, p. 29

14.1 Does Terasen agree that reductions in consumption due to increases in natural gas rates, where those increases are in excess of inflation, are a form of DSM? If not, please explain why not.

Response:

While there is generally a correlation between rising natural gas commodity prices and falling use per account, the Companies would not typically refer to such a price response as "DSM". Natural gas commodity prices are a pass-though to the Companies' customers and natural gas rates in British Columbia rise and fall in response to changes in North American commodity prices, not as part of a conscious program to reduce customer demand. The marginal supply of natural gas commodity is visible to customers as it is a flow-through to customer rates; one would assume that an increase in price elicits a demand response in customers. It is important for customers to receive a price signal that reflects the marginal cost of supply as a foundation for conservation activity, however the Companies believe that relying on price signals alone will not capture all the conservation opportunities that are available. The Companies believe that utility-funded conservation activity has an important role to play in the marketplace, in conjunction with energy pricing that reflects the cost of acquiring that energy, as is the case with natural gas rates. The January 2006 Summit Blue report, prepared for CAMPUT, filed in response to BCUC 1 85.1, notes on page 1 that:

> *"Overall spending levels have, in most cases, not been at a level sufficient to realize most of the cost-effective DSM in any jurisdiction"*

The Companies believe that this would indicate that pricing signals alone cannot capture all the conservation opportunities available.

14.2 Please provide a listing or table of the own price elasticities Terasen currently uses for each of its customer rate classes.

Response:

The Companies estimate price elasticity through regression analysis, specifically a logarithmic model that determines the relationship between the natural log of annual consumption per customer and the natural log of the average annual natural gas commodity price. Current analysis indicates the own price elasticity for residential customers is 21% and for commercial customers is 17%, however the Companies do not rely on these factors for the purposes of its demand forecasting.

Although it is recognized that customers do change their short-term behaviour when faced with sudden and significant commodity cost increases, long-term changes in use per customer rates for mature gas utilities are more a function of advances in heating technology and home construction techniques, both of which improve on an ongoing basis regardless of natural gas costs. Sudden increases in natural gas prices may accelerate the decision to purchase more efficient equipment, but once that purchase has been made the impact on consumption (related to the new equipment) is permanent regardless of whether prices later moderate. It is for this reason, and also the fact that it is difficult to isolate demand responses to only price, that the Terasen utilities use price elasticities more as a variable to monitor over time rather than adopting as a driver of demand.

15.0 Reference: Exhibit B-1, Section 3.4, Customer Usage Rates, p. 32

15.1 Figure 3.4b shows the trend of Normalized TGVI Residential use rates over time. Please confirm that for any residential or commercial class there is no longer a surcharge for annual loads that fall below a certain amount (e.g. 53 GJ for residential customers).

Response:

Confirmed.

15.2 The Application states that the funding requested in the Application is to increase customers' use of efficient natural gas equipment and buildings, "…which will continue to drive customer use per account down, in accordance with government policies related to conservation."

15.2.1 Has any government policy identified a specific use per account target for natural gas use? If please identify the policy or policies.

Response:

The Companies are not aware of a government policy announcement that has identified a specific use per account target for natural gas use. The passage was referring more generally to government's GHG reduction targets and energy efficiency.

15.2.2 Can Terasen confirm that the government in the Greenhouse Gas Reduction Targets Act which came into effect on January 1, 2008, states that:

"The following targets are established for the purpose of reducing BC greenhouse gas emissions:

(a) by 2020 and for each subsequent calendar year, BC greenhouse gas emissions will be at least 33% less than the level of those emissions in 2007;"

Response:

Based on the extract above, the Companies can confirm that it would appear that the government has established these absolute targets for GHG emission reductions.

15.2.3 Can Terasen confirm that a program that encouraged the purchase and use of discretionary appliances, such as gas fireplaces, would increase GHG emissions in British Columbia if the purchase and use of such appliances represents incremental gas use? If not, why not?

Response:

Efficient gas fireplaces can be used as a heating source. It is the position of the Companies that GHG emissions should be considered on a regional basis, as is the intent of the Western Climate Initiative, which British Columbia is part of. GHG emissions within the region would be lowered in instances where an efficient gas fireplace used as a heating source can displace electrical space heating where the electricity consumed is generated through the inefficient combustion of fossil fuels. It is the Companies' view that consumers will likely still want to buy fireplaces, even in a carbon-constrained world, and that the Terasen Utilities should encourage the use of the most efficient gas appliances available. In the case of fireplaces, the Companies would work to increase the market penetration of Enerchoice labeled, heater-style gas fireplaces rather than purely decorative gas fireplaces. Enerchoice is a designation that has been developed by the Hearth, Patio and Barbeque Association of Canada's BC chapter, and it is award to fireplaces with Energuide ratings that fall in the top 25% of Energuide ratings for all fireplaces.

The same is true of discretionary electrical appliances such as flat-screen televisions and electric fireplaces, which also increase GHG emissions in the region. The Companies are of the view that this will continue to be the case in the future, even when the Province reaches the point of electric self-sufficiency. Consumers will more than likely still want to purchase these appliances, even in a carbon-constrained world and the goal of any program should be to encourage consumers to purchase the most efficient version of these appliances.

Please see also the response to BCUC 1. 23.4.

16.0 Reference: Exhibit B-1, Section 3.5, Expenditures by Other Utilities, p. 35

16.1 Please explain how NW Natural spends over $10 million on DSM yet only has 1 full time DSM employee.

Response:

NW Natural collects $11 million dollars annually from its customers for various DSM activities through a Public Purpose Fund. However, approximately $9 million of the $11 million is funneled to the Energy Trust of Oregon (ETO) for various energy efficiency programs. The ETO was established by the Oregon State Government with a purpose to administer energy efficiency programs without a bias towards any energy source.

With the remaining $2 million, NW Natural funds low-income weatherization programs. While currently there is only one full-time employee dedicated to energy efficiency, there are up to four full-time at NW Natural who can be assigned to provide additional support as required.

16.2 For the combined gas and electric companies, is it possible to separate DSM expenditures for natural gas customers only?

Response:

Through research, we were able to obtain the natural gas DSM budget for two of three combined utilities referenced in Appendix 4 of the Application.

Manitoba Hydro's DSM budget for natural gas programs for 2006/2007 was $9 million dollars, while the budget for 2007/2008 was set for $11 million.

PSE's natural gas DSM budget for 2007 is as follows:

	Residential	Energy Savings	Commercial Industrial	Energy Savings	Other Initiatives	Energy Savings
Electric	$ 17,050,000	71,246 mWhs	$ 18,190,000	101,706 mWhs	$ 3,150,000	14500 mWhs
Gas	$ 3,850,000	118,000 GJs	$ 1,660,000	102,000 GJs	$ 590,000	N/A
Total Budget	$ 20,900,000		$ 19,850,000		$ 3,740,000	

PG&E was unable to provide an exact breakdown for natural gas vs. electric because the utility divides its DSM expenditures by target market rather than by fuel type; however, through telephone conversation with PG&E staff estimated that 14% of expenditures are related to the natural gas side of the utility.

16.3 Please confirm that the PG&E DSM budget in the table is for electric and gas initiatives, that the number of DSM employees includes those working on electric and gas programs and that the customer count includes only gas customers.

16.3.1 To the extent possible, please provide a revised version of Table 3.5 that disaggregates the gas and electric sector activities and customers for the combined utilities (PG&E, Manitoba Hydro, Puget Sound Energy).

Response:

Correct. The PG&E DSM budget in the table is for electric and gas initiatives. However, note 9 on Table 3.5 in the Application is incorrect and should read: "this figure reflects the total number of DSM staff at PG&E, approximately 80% of staff time spent on <u>electric (not natural gas)</u> DSM Programs.

The Revised DSM Comparison Table follows.

DSM Comparison Table

Company Name	Utility Type	2007 DSM Annual Budget ($ in millions)	Start DSM year	DSM Funding Treatment	Company Earns on DSM [7]	Return on Equity or Incentive Mechanism	Customer Base	F/T DSM Employees	Total Employees	2006 Asset Base ($ in millions)	2006 Total Revenues ($ in millions)	% Spent on DSM of Revenue	DSM Spent per customer	2006 Annual Sales Volume (PJs)
Pacific Gas and Electric Company ("PG&E")	Combined	279.0 [1]	mid-1970's	Public Purpose Fund	Yes	Incentive Mechanism	5,100,000(E) 4,200,000 (NG) [10]	350 [13]	20,000	34,800	12,530	2.23%	$66.43	425.9
TGVI (Based on approved EEC Budget)	Natural Gas	2.8	2004? [5]	DSM costs are treated as capital and amortized over a fixed time period.	Yes	Yes	90,738	12 [14]	103	467	172	1.65%	$31.19	28.0
Manitoba Hydro	Combined	9.0	1989	DSM costs are treated as capital and amortized over a fixed time period.	No	N/A	516,800(E) 259,569 (NG) [11]	50	3,200	11,000	517	1.74%	$34.67	147.6 [23]
Southern California Gas Company ("SoCal Gas")	Natural Gas	56.6 [2]	mid 1980's	Public Purpose Fund	Yes	Incentive Mechanism	5,600,000	30	3,000	6,360	4,180	1.35%	$10.11	946.0
BC Hydro and Power Authority ("BC Hydro")	Electric	52.3 [3]	late-1980's	DSM costs are treated as capital and amortized over a fixed time period.	No	N/A	1,704,671	131	4,200	12,484	4,311	1.21%	$30.68	190.5
FortisBC	Electric	2.5	1989	DSM costs are treated as capital and amortized over a fixed time period.	Yes	Both	154,000	8	570	731	208	1.19%	$16.06	11.1
Northwest Natural Gas Company ("NW Natural")	Natural Gas	11.0 [4]	1980	Public Purpose Fund	No [8]	N/A	636,000	1	1,211	1,957	1,000	1.10%	$17.30	125.8
Union Gas	Natural Gas	17.0	1997	DSM costs are recovered through rate base	Yes	Incentive Mechanism	1,300,000	45	2,200	4,600	2,100	0.81%	$13.08	1,303.0 [24]
The Terasen Utilities (Based on approved EEC Budget)	Natural Gas	16.8	1991	DSM costs are treated as capital and amortized over a fixed time period.	Yes	Yes	911,935	12 [15]	1,229	2,909	1,655 [21]	1.02%	$18.45	208.0 [25]
TGI (Based on approved EEC Budget)	Natural Gas	14.0	1991	DSM costs are treated as capital and amortized over a fixed time period.	Yes	Yes	821,197	12 [16]	1,107	2,442	1,483	0.94%	$17.04	180.0
Enbridge Gas Distribution ("Enbridge")	Natural Gas	22.0	1995	DSM costs are recovered through rate base	Yes	Incentive Mechanism	1,800,000	45	1,961	3,323	3,016	0.73%	$12.22	445.0
TGVI	Natural Gas	1.2	2004? [6]	Program costs as O&M; program incentives are amortized over fixed time period	No	N/A	90,738	4 [17]	103	467	172	0.67%	$12.67	28.0
Gaz Metro Limited Partnership ("Gaz Metro")	Natural Gas	8.8	1999	as O&M	Yes	Incentive Mechanism	167,000	6 [18]	1,500	2,700	2,000	0.44%	$52.69	271.8
The Terasen Utilities	Natural Gas	4.3	1991	Program costs as O&M; program incentives are amortized over fixed time period	No	N/A	911,935	4	1,229 [20]	2,909	1,655 [22]	0.26%	$4.69	208.0 [26]
TGI	Natural Gas	3.1	1991	Program costs as O&M; program incentives are amortized over fixed time period	No	N/A	821,197	4 [19]	1,107	2,442	1,483	0.21%	$3.80	180.0
Puget Sound Energy ("PSE")	Combined	6.1	early-1980's	DSM costs are recovered via a rider on customer bill	Yes	Incentive Mechanism [9]	1,000,000(E) 718,000 (NG) [12]	80	2,400	7,061	2,905	0.21%	$8.52	205.1
SaskEnergy	Natural Gas	1.6	2001	as O&M	No	N/A	325,000	4	1,000	1,322	1,254	0.13%	$4.92	125.0
ACTO Gas	Natural Gas	Part of marketing budget	2001	as O&M	No	N/A	969,200	8 - 12	1,700	7,698	2,890	N/A	N/A	219.0

Comments:

[1] This figure reflects the 2007 DSM budget for electrical and gas initiatives. This covers labor, rebates and advertising. An additional $24 million will be spent on research and evaluation. On average, 86 per cent of funds are related to the electric side.

[2] This figure reflects the 2007 DSM budget which covers labor, rebates and advertising. An additional $4.3 million will be spent on research and evaluation.

[3] This figure is comprised of the following components: $4.9 million (operating costs) and $47.3 million in deferred capital - note that it is an actual figure rather than a budget figure.

[4] This figure is the sum of $9 million that is dedicated for DSM and market transformation programs implemented through the Energy Trust of Oregon (ETO) and $2 million for low income weatherization administration by NW Natural.

[5&6] Historically, DSM activity on TGVI has not been well-defined or well-reported upon as the activity for TGI. 2004 is shown as a start year as per BCUC's Order No. C-02-05 mentioned in the Application on p.26.

[7] The utility either earns a return on equity, on a financial incentive or on penalty that is based on DSM Mechanism.

[8] There is a separate line on customers' bill; DSM costs are treated as flowthrough costs.

[9] PSE has an incentive and penalty mechanism for electric programs.

[10, 11 &12] As per IR 16.3.1, these cells show both electric (E) and natural gas (NG) customers for combined utilities; DSM Spent Per Customer is based on NG customers only.

[13] This figure reflects the total number of DSM staff at PG&E, approximately 80% of them spend their time on electric DSM programs.

[13, 14 & 16] Proposed combined (TGI and TGVI) staffing requirements as per EEC Application p.79

[17 &19] Currently Terasen Gas has a core Energy Efficiency & Marketing staff of four; their time is split between TGI &TGVI.

[18] Overall, over 200 employees, contractors, business partners involved in the delivery of DSM programs at Gaz Métro.

[20] This count includes all FTR employees, both active and inactive, as well as dependent contractors at TGI, TGVI and Terasen Inc. It doesn't balance to the original number of 1237, reported as of Sept 30, 3007, because of retroactive entries made in the Human Resources Information System.

[21&22] These are combined revenues for Terasen Gas Inc. and Terasen Gas Vancouver Island which includes TGI & TGVI Gas Sales and Transportation Revenues.

[23] Includes sales for residential, commercial and industrial sectors and transportation services.

[24] This number is comprised of 509 PJ for distribution and 794 PJ for transportation.

[25& 26] This includes the total volume numbers for TGVI (including ICLP/Hydro; VIGJV-Inland & Squamish Gas) and TGI.

16.4 Note 5 to the column labeled "Company Earns on DSM" states that "The utility either earns a return on equity or on a financial incentive or penalty based on DSM mechanism". In the revised table requested in the question directly above, please indicate in the cells in the "Company Earns on DSM" column which method (return on equity or financial incentive/penalty) is used.

Response:

Please refer to the response to BCUC IR 1.16.3.1.

16.5 Also in the revised table please provide a line for each of TGI and TGVI with information that would be correct if the Application is approved in its entirety.

Response:

Please refer to the response to BCUC IR 1.16.3.1. Please note that the table reflects the proposed expenditure for both utilities combined, and for TGI and TGVI separately, for 2008.

16.6 The row for Manitoba Hydro indicates that DSM costs are treated as capital and amortized over a fixed time period, but that the Company earns no return on DSM. Please explain.

Response:

Please refer to the response to BCUC IR 1. 43.2.4.2.

16.7 To the extent possible, please provide a spreadsheet or supplementary table that breaks out the expenditures of other utilities by sector, and by spending on incentives, administration, education, and trade relations.

Response:

The research for the DSM Comparison Tables was conducted by the Companies' own staff. The information presented in this table is sourced from utility websites, public websites, utility commission, and government websites. Information on these sites is usually presented in summary form. The details for spending on incentives, administration, education and trade relations are reported differently for each utility and are rarely presented on public sites. The work needed to gather the breakdown of spending, and ensure that the information is presented in a consistent manner for each utility would be significant and time-consuming, and is not possible in the time frame available.

17.0 Reference: Exhibit B-1, Section 3.5, Expenditures by Other Utilities, p. 37

17.1 Are any of the PowerSmart expenditures identified on page 37 directed at load building? If so, please identify the types of load building programs and the percentage of total PowerSmart expenditures directed at load building.

Response:

None of the PowerSmart expenditures identified on page 37 of the Application are directed at electrical load building. (This is based on the DSM budget figure taken from "BC Hydro F09/F10 Revenue Requirement Application, Section 5, Page 7, Table 5-1, "Capital Expenditure by Business Function" and from Appendix C (BC Hydro Service Plan 2008/09 – 2010/11), p.19 of 37 lists DSM activities but load building is not mentioned.)

Electrical load building by BC Hydro would be inconsistent with the requirement on BC Hydro to achieve self-sufficiency plus insurance, and also specific load reduction targets on BC Hydro. Load building from the perspective of the Companies involves different considerations. As outlined in the response to BCUC IR 1.2.4, much of load building involves oil and propane to gas fuel switching on Vancouver Island. Moreover, electric to gas fuel switching (or load building, from the Companies' perspective) supports the Province's conservation and self-sufficiency objectives, as well as reducing GHGs on a regional basis. Please refer to the response to BCUC IR 1.62.1.

17.2 Are any of the PowerSmart expenditures identified on page 37 directed at fuel switching? If so, please identify the types of fuel switching programs and the percentage of total PowerSmart expenditures directed at fuel switching.

Response:

It is the understanding of the Companies that none of the PowerSmart expenditures identified on page 37 of the Application are directed at fuel switching.

Please also refer to the response to BCUC IR 1.17.1.

18.0 Reference: Exhibit B-1, Section 3.5, Expenditures by Other Utilities, p. 38

The Companies state:

"Given that natural gas comprises approximately the same percentage of the energy consumed in British Columbia as electricity, it is the view of the Companies that natural gas customers should have the same access to programs to help them conserve energy as do electricity customers."

18.1 Do the Companies agree that the price of electricity is regulated and set at a price equal to the average historical cost, which currently is well below the long run cost of supply, and that the price of the natural gas commodity is determined in a competitive international market? If so, does that fact enter into the Companies' view that natural gas and electricity customers should have the same access to DSM programs? If so, how?

<u>Response:</u>

The Companies agree that the cost of electricity embedded in current regulated electricity rates is based on average historical costs that are well below the long run marginal cost of new supply. The Companies also agree that the price of the natural gas commodity is competitively determined in the context of a North American market.

The different competitive commodity market circumstances of the two energy sources do not affect the Companies view that comparable DSM programs should be available to both. Further, the Companies see no differentiation in the UCA between electricity and gas in relation to DSM activities and energy efficiency expenditures. Gas customers experience the price signals of market commodity prices fluctuations more directly than electricity customers do. In the absence of suitable DSM opportunities these price signals may cause gas customers to switch to using electricity, which may not be a desirable outcome. Refer to the response to BCUC 1.15.2.3. Presently, consumers that switch from natural gas to electricity do not themselves experience the full cost impact of switching energy sources since their electricity rates are based on average historical costs whereas the cost impact of their increased consumption affects costs at the margin. (Conservation rates, such as BC Hydro's Residential Inclining Block rate, may mitigate this to the extent that increased electricity consumption from switching comes from a higher-priced block.) To the extent that gas customers respond to gas commodity price volatility by switching to electricity the overall provincial energy objectives of reducing energy consumption and improving energy conservation and efficiency may be thwarted and could result in squandering of the Heritage resources.

Further, the Companies are of the view that both gas and electricity DSM programs should be subject to the same overall cost-benefit standard, namely that the portfolio of all program areas combined should have a TRC greater than 1.0. The program areas proposed by the Companies in this Application do have a TRC greater than 1.0, indicating that cost-effective natural gas energy savings opportunities exist. The Companies are of the view that natural gas customers should not be denied the opportunity to participate in cost-effective natural gas EEC activity.

18.2 Do the Companies feel that the same logic should be applied to other energy commodities such as gasoline or home heating fuel?

Response:

As compared with natural gas and electricity which are regulated utility services, gasoline and home heating fuel are sold in competitive markets down to the retail level. Without a regulator like the BCUC reviewing and approving DSM initiatives the programs and mechanisms to reduce consumption of these products are of necessity quite different.

Using gasoline is optional in many circumstances. Using public transit, riding a bicycle or walking are viable alternatives to driving a vehicle in various situations. Gasoline consumption can also be reduced by acquiring a more fuel efficient vehicle or adopting appropriate vehicle maintenance practices and driving habits. Some government programs are aimed at taking older less fuel-efficient vehicles off the road or providing incentives towards the purchase of more fuel-efficient vehicles. Improving traffic flow and designing communities which support less vehicle use are additional areas which could bring about reduced gasoline consumption. New technologies such as plug-in hybrid vehicles, NGV and LNG offer the prospect of reduced gasoline use. The B.C. Carbon Tax is further mechanism being adopted to reduce fossil fuel (i.e. gasoline) usage. The foregoing items are a small sample of possible avenues to bring about the equivalent of DSM for gasoline. These items demonstrate that reducing the use of gasoline is a much more complex process involving many parties and various levels of government than utility DSM programs would typically be. Government policy, legislation, taxation and programs along with the price signals of market commodity prices are the main instruments effecting behaviour change.

Home heating fuel has more resemblance to a utility service than gasoline however consumers likely have the opportunity to choose between suppliers. Heating oil users should have similar access to DSM opportunities as natural gas and electricity consumers. If market mechanisms are not available funding through government programs may be necessary to make such opportunities possible.

19.0 Reference: Exhibit B-1, Section 3.6.2, Municipal Policies, p. 43

19.1 The Application states that a portion of EEC funding, as discussed in Section 6.6.4, will be used to co-fund specific municipal programs. How will the benefits of programs co-funded with municipalities be attributed? If the co-funding was with BC Hydro, would the Companies attribute benefits the same way? Why or why not?

Response:

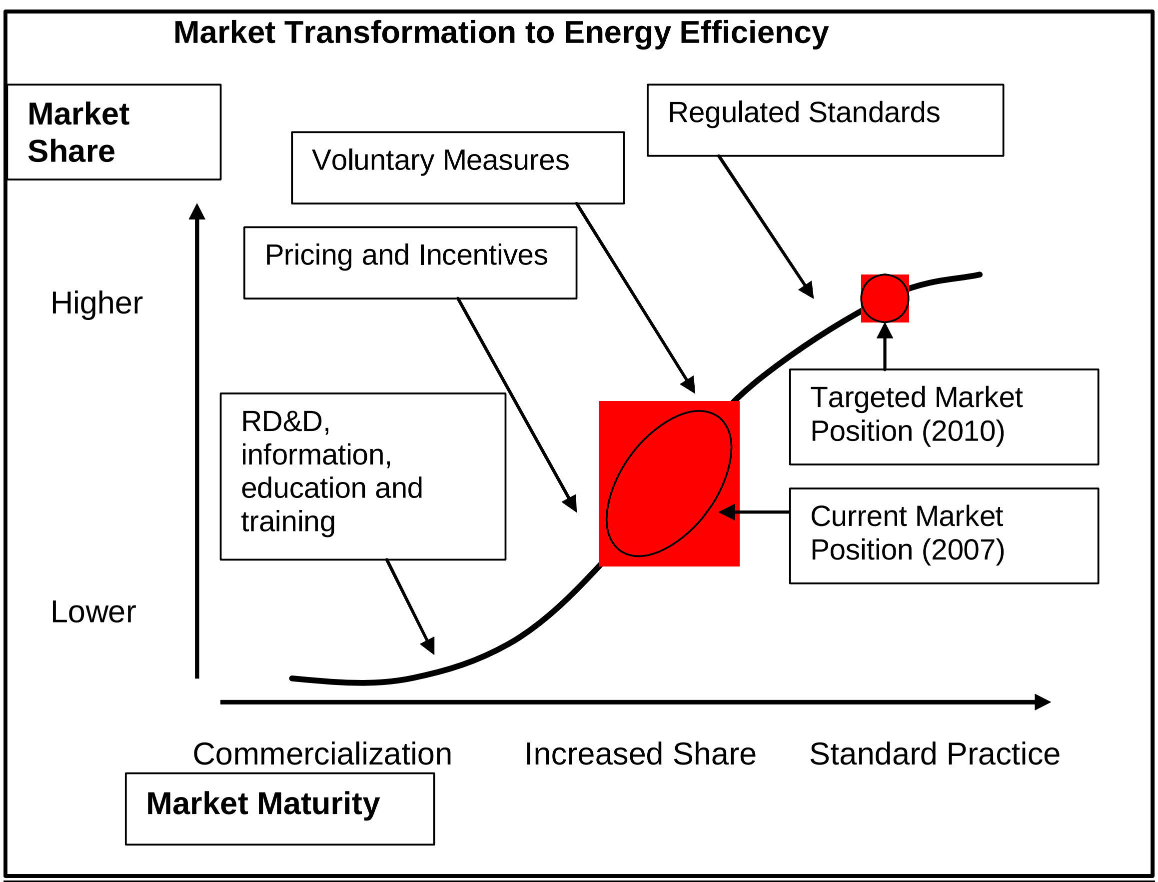
These programs have not yet been developed, so it is premature to say how benefits of co-funded programs would be attributed, beyond stating that benefits should be attributed based on proportional contributions by funding and program partners. In the case of past programs co-funded with BC Hydro, the benefits that arise from providing funding for the natural gas incentives in such programs have been attributed to the Companies. This is a matter for discussion and consideration by the British Columbia Partnership for Energy Conservation and Efficiency (BCPECE), which has been convened by MEMPR in order to coordinate DSM activity within the Province. The Terasen Utilities are active members of the steering committee for BCPECE, as well as being involved with the various working groups. Other members are the BCUC, MEMPR, BC Hydro, FortisBC and Pacific Northern Gas.

20.0 Reference: Exhibit B-1, Section 5, Market Transformation, p. 48

20.1 For each of the sectors targeted, please explain how the Companies intend to effect market transformation.

Response:

The figure below outlines a path to market transformation to energy efficiency, that is, a market where efficient equipment is regulated as "the norm" by codes and standards, and efficiency levels are being pushed ever higher. For the residential and commercial building sectors, the Companies have a role to play in preparing the marketplace for the introduction of Regulated Standards. The areas where the Companies could contribute to market transformation would be in disseminating information and educating stakeholders about efficient products, systems, and buildings; in supporting training related to the design, installation and maintenance of efficient products, systems and buildings; addressing price barriers through incentives; supporting the development of voluntary measures and advising government on the development of Regulated Standards. It is because of the role that the Utility can play in paving the way for the introduction of Regulated Standards that the Companies believe that energy savings resulting from regulation should be attributed to utility programs, as detailed in section 6.13 of the Application on page 87.



21.0 Reference: Exhibit B-1, Section 6.2.2, Joint Initiatives, Trade Relations and the 2009 CPR, p. 53

The Application states that the estimate for the 2009 CPR is based upon a cost to perform the previous CPR of approximately $300,000 and includes an allowance for the kind of work done by Habart to refine the CPR results into a DSM program.

21.1 How much did Terasen estimate for the 2009 CPR and is that based on a quote from Marbek or on a Terasen estimate? To what extent does Terasen think that the 2009 CPR should cost less than the previous CPR because of the ability to rely on information and methods developed for the previous CPR?

Response:

The number is not based on a quote from Marbek. It is based on an estimate developed by the Companies, based on a cost for the previous CPR of approximately $300,000 plus an allowance of $100,000 for costs for the type of work that Habart and Willis Energy (who developed the spreadsheet models used for the cost-benefit analysis) performed in order to work up a budget, plus an allowance of $100,000 for cost inflation from the last CPR. While there were information and methods developed for the previous CPR, the Companies would put work of this type out to an RFP. It may be that the successful respondent proposes a different methodology which would reduce the potential cost reduction associated with using the methodology developed for the previous CPR. It should be noted as well that since the last CPR was completed, demand has grown for experienced consultants to do demand side management-related work. The Companies anticipate that this may place upward pressure on the cost for the 2009 CPR.

21.2 How much did the Habart Study in the Application cost, and is Terasen assuming the same level of work to be associated with the 2009 CPR?

Response:

The Habart Study, which included CPR Review, development of the Assumption Sheets, program concept development and the two reports (CPR Measure Update and Review of Conservation Potential) cost $61,895.00 (this includes the work completed in 2007 and in 2008). It is anticipated that the same degree of effort will be required for the 2009 CPR. However, the Terasen Utilities were able to draw on the services of an experienced consultant for this work that might not be available in 2009. Therefore, the costs for consultant(s) in 2009 might be somewhat higher.

22.0 Reference: Exhibit B-1, Section 6.3.1 Market Transformation, p. 58

22.1 The Companies state "This document constitutes the Companies' Application for DSM programs for the New Construction Market."

Please provide a summary of each such program, including incentive levels, number of participants and values for the TRC, RIM and Utility Test for each program. Please provide the test calculations in the form of fully functioning spreadsheets, and any other related spreadsheets, showing the complete detail of each calculation.

Response:

Due to the commercial sensitivity of the information requested, the response to this question has been filed under separate cover in accordance with the BCUC Practice Directive pursuant to Section 13 of the *Administrative Tribunals Act* related to Confidential Filings. The Terasen Utilities have requested that the information be made accessible only to the Commission and to those authorized representatives of Registered Intervenors who execute an undertaking, consistent with Attachment A to the BCUC Practice Directive, to hold the information confidential.

23.0 Reference: Exhibit B-1, Section 6.2.2, Residential Energy Efficiency, Enerchoice Fireplaces, pp. 59 - 61

23.1 Please summarize, with reference to the CPR where appropriate, the characteristics of fireplace use (e.g. on average how many days per year are they on, what percentage of gas fireplaces are fed from a commonly metered piping system).

Response:

Based on the 2006 Terasen Gas CPR, residential fireplaces account for 13% of gas consumption in a household per year. The average gas fireplace uses approximately 20% as much energy as a primary gas heating appliance (Source: 2006 Terasen Gas CPR pg 18). The BC Gas, Residential End Use Survey Results, Dec 2003, contains more detailed consumption data on two types of gas fireplaces: heater-type fireplaces and decorative fireplaces. The consumption of the two types differs by less than 10%, although decorative fireplaces essentially make no contribution to heating the home.

Most gas fireplaces are fed from a common metered piping system. Some multi-family developments have installed individual metering for only fireplaces. The Companies do not encourage this as it is costly for the end user. The Terasen Utilities do not track what percentage of developments may have installed meters for only fireplaces.

Based on the most recent information available, the annual hours of fireplace operation for the Lower Mainland service area is 519 hours and 563 hours for the Interior service area.

23.2 What is the range of efficiency of all gas fireplaces? What would be the efficiency range of those fireplaces in the top 25% efficiency ranking?

Response:

All vented fireplaces sold in Canada must now be tested for their energy efficiency using the Canadian Standards Association CSA-P-4.1-02 standard, if they are shipped across provincial lines. The energy efficiency rating of the fireplace is either on the EnerGuide label or in the product's technical information when multiple models are listed. The rating is expressed as a percentage. The higher the percentage, the more energy efficient the model.

Fireplaces range in efficiency from about 20% to 70% percent, although there are models that are rated up to 80% efficiency. Natural Resources Canada website contains a list of models for gas fireplace efficiency ratings. The efficiency range of those fireplaces in the top 25% efficiency ranking are from 60-80%.

(Source:http://oee.nrcan.gc.ca/equipment/english/fireplace-search.cfm?text=N&printview=N.)

23.3 Would the level of the proposed fireplace incentive be established relative to the incremental cost differences between 'efficient' and 'inefficient' gas fireplaces?

Response:

The incremental cost difference between an efficient fireplace and an inefficient fireplace is one of the factors considered when an incentive intended to induce a consumer to purchase an efficient model vs. an inefficient model is established. Other factors include to whom an incentive should be provided – the manufacturer, the distributor, the retailer, a builder and/or an end user and/or more than one of those parties; and how much incentive is required to influence behaviour in the target participant, as it would vary from participant group to participant group.

23.4 How would Terasen avoid unintended consequences, such as encouraging customers to install electric baseboard heat plus a fireplace rather than an efficient gas furnace?

Response:

This can be avoided by encouraging and educating consumers on how to use energy resources efficiently. It's important to match an energy source to its best use. Electricity is best suited for lighting and powering appliances and televisions, whereas natural gas is ideal for space and water heating. Educating consumers regarding the direct use natural gas appliances for space heating would help the Companies to avoid unintended consequences.

The direct use of natural gas for space heating in BC homes and businesses makes BC hydroelectricity available for export throughout the region. These "clean" exports offset electricity generation elsewhere in the region. Since the marginal source of electricity generation in the region is natural gas fired (or even coal fired) generation, which operates at much lower efficiency than high efficiency natural gas furnaces, the direct-use of natural gas for space heating supports both the climate action and energy conservation targets.

The following excerpt supports the Companies' view above and is from the US Federal Energy Management Program Spring 2004 newsletter, filed as evidence in Exhibit C7-10 of the BC Hydro Rate Design Application 2007.

> *"Electric efficiency and conservation: Throughout most of the U.S., natural gas power plants operate on the margin at least half of the time and in a number of regions (the West, Southwest, Texas, Florida, and New England),they operate on the margin 80 to 90 percent of the time. Electricity users can therefore indirectly decrease natural gas consumption-and thus help to put downward pressure on prices-by reducing their electricity use, particularly during daytime hours when natural gas is most likely to be the marginal fuel source for electricity generation.*

> *In fact, in many cases, electric efficiency efforts provide the "biggest bang for the buck." Federal agencies can build on their reputation as leaders in promoting the efficient use of electricity by engaging in measures such as retrofitting lighting and HVACsystems, installing or recommissioning energy management systems, and establishing energysmart operational practices."*

Educating consumers on the provincial energy landscape and working with government to ensure energy appropriate energy policies are key components to meeting the objectives of the Province.

23.5 The Companies expect to launch the retrofit program for Enerchoice Fireplaces in partnership with the Hearth, Patio & Barbeque Association of Canada, but no such partnering appears to be proposed for the New Construction program? If there is a distinction between the partnering approach to the new construction relative to the retrofit markets, what is the distinction and why is it appropriate for EEC partnering?

Response:

The Companies will continue to partner with the Hearth, Patio & Barbeque Association of Canada for both the retrofit program as well as the New Construction program, however a New Construction program will also include partnership with the Canadian Home Builders' Association of British Columbia and its various regional affiliates.

24.0 Reference: Exhibit B-1, Section 6.2.2, Residential Energy Efficiency Program Area, p. 60

24.1 What is the expected life of a pre-1976 furnace?

Response:

The anticipated lifecycle of a pre 1976 furnace is 18 years

Source: ASHRAE 2007 handbook – HVAC Applications Chapter 36, Owning and Operating Costs, Table 4.

24.2 What kind of direct input has Terasen had in developing the federally mandated 90% minimum efficiency level for furnaces planned for 2009?

Response:

The Terasen Utilities have not had any direct input into federal standards for 90% efficient furnaces. The Companies did however provide comment on the adoption of high efficiency furnace standards at the provincial level.

24.3 How does Terasen propose to attribute the benefits of its program for the 8,180 furnaces the Companies expect to fund up to the end of 2009, and for furnaces installed in 2010 and later years?

Response:

For furnaces installed from the introduction of a regulation and for the five subsequent years, the Companies would propose that the attribution schedule in Table 6.13b of the Application be followed. Please note, however, that the cost-benefit ratios presented in the Application and Appendix 11 do not include attributed savings from the installation of furnaces post-regulation.

24.4 The Application states that this years' Energy Star Heating Upgrade program running from September 1, 2007 to March 31, 2008 is projected to have 3300 participants, a "notable gain" in program participation.

Can the Companies offer an explanation as to why the notable gain in program participation occurred?

Response:

The Companies have not done research specifically into why this gain in program participation has occurred, so any response that the Companies could provide would be speculative. However, some of the potential reasons could include:

- An improvement in the performance of high-efficiency heating products from the introduction of the technology to now
- Customer familiarity with high-efficiency heating products and their benefits
- Contractor familiarity with high-efficiency heating products and their benefits
- An increase in general awareness about energy, costs and the value of conservation

The increase in participation over the time frame supports the Companies' proposal that programs should be multi-year in order to provide the marketplace with certainty.

25.0 Reference: Exhibit B-1, Section 6.2.2, Commercial Energy Efficiency Program Area, pp. 60-62

25.1 Please provide a table showing how the $21.7 million proposed for Commercial Energy Efficiency programs will be allocated by Utility, by year and by program.

Response:

Please see the workbooks filed in response to BCUC IR 1.56.2. There are two scenarios filed in the response to BCUC IR 1.56.2 – analysis that accounts for free rider effects and analysis that excludes free rider effects.

Page 4 of each workbook provides information on expenditure by year, by program and in summary form, as well as cost-benefit results. There are workbooks for TGI Commercial as well as for TGVI Commercial.

25.2 The Application states that with respect to energy efficiency for commercial retrofits, more detailed program work must be completed by the Companies in conjunction with industry groups before these programs are rolled out. Please describe the type of detailed program development work to be completed.

Response:

The Companies need to consult with the following groups: Building Operators and Managers, Building Owners and Developers, as well as Equipment Suppliers and Engineers. Detailed program development work needs to be conducted in order to understand the following:

- Potential costs of the some of these retrofit opportunities to the participant;
- Incentive level and the type of incentive (prescriptive or performance based or a combination thereof) needed to spur participation;
- How best to combine measures into programs to ensure optimal participation
- The interplay of different equipment in engendering energy savings, and how to attribute energy savings to a certain measure or bundle of measures based on that interplay;
- Any supporting studies such as engineering studies needed to engage participation
- How best to deliver commercial retrofit programs
- How to ensure that qualified installers for retrofit measures are available
- How to ensure that any training needed to operate efficient technologies will be available

26.0 Reference: Exhibit B-1, Section 6.4, Fuel Switching, pp. 63-64

26.1 Terasen states that fuel substitution initiatives benefit all customers by ensuring that the Companies' distribution infrastructure is used to its maximum efficiency. Could all of the fuel-switching and fuel substitution programs proposed in the Application also be described as load building programs? If not, why not?

Response:

Page 2 of the California Standard Practice Manual describes fuel substitution as "the choice of one fuel over another" and load building as "increasing sales of electricity, gas or electricity and gas". Given these definitions, the answer to whether the fuel-switching and fuel substitution programs could also be described as load building programs as this would depend on whether the perspective being taken was on the energy system in the province as a whole, or looking at one energy source in isolation. If one was looking at natural gas in isolation rather than at the energy system in the province, then fuel substitution programs could be described as load building programs, however from an integrated perspective, reducing consumption of one energy source and replacing it with another would more accurately be described as fuel switching or fuel substitution.

26.2 Would there be any disadvantage in making the fuel switching program available in areas other than the TGVI service territory, even though the uptake may be low?

Response:

No. In fact, having the same programs available to all customers throughout the Companies' service territory will reduce customer and supplier confusion and provide the same types benefits to customers of TGI and TGVI.

26.3 The Companies state on page 64 that to encourage the use of natural gas among its customers, the Terasen Utilities would offer installation of natural gas water heating along with natural gas space heating equipment and that the Companies "…may bundle this program as a package with Energy Star Appliances". The Companies also propose that TGVI and TGI qualified applications will receive an incentive if they install one or both of a natural gas range and/or dryer.

Would it be part of the Terasen promotion that any of the appliances included as part of a package, or for which incentives are offered, would be Energy Star Appliances (assuming it is a type of appliance for which Energy Star labeling is available)? If not, why not?

Response:

The Companies are of the view that to be eligible for an incentive, appliances would need to be Energy Star rated if there is an Energy Star rating available to that type of appliance.

27.0 Reference: Exhibit B-1, Section 6.4 Heating System Upgrades, p. 65

27.1 Please explain the statement "The current regulatory regime for TGVI does not allow Terasen to offer customers who switch to natural gas an incentive to install Energy Star equipment."

Response:

As outlined in Section 3.2.2, BCUC Order No. C-02-05 noted that:

> *"Currently, the DSM strategy is mixed with marketing efforts…The Commission Panel expects that a more detailed long-term DSM plan will accompany future annual updates and will contain information as outlined in the Recommendations in Chapter 6 of the Decision. The Commission Panel recommends that TGVI seek approval through the Resource Plan review process for the DSM budgets and projects…"*

As noted on page 26, this EEC Application represents TGVI's request for approval for DSM budgets and projects. The Companies have historically proceeded under the assumption that the previously approved "mixture of DSM strategy with marketing efforts" meant that efforts in the past should be focused on load building rather than on conservation for TGVI. The Companies are proposing in the EEC Application that both load-building and conservation programs, such as offering TGVI customers a TGVI-funded incentive to install Energy Star equipment, should be offered to TGVI customers, and are hoping that the Commission approval of this Application will clarify the type of EEC activity that it is appropriate for TGVI to conduct.

27.2 The Application states that "Existing residences in the TGVI service territory will be offered an incentive not only for switching to natural gas, but also for installing Energy Star Equipment.

Can TGVI confirm that the incentives will be offered only if the customer also installs Energy Star equipment? If not, why not?

Response:

If the EEC Application is approved, incentives would be offered only to those TGVI customers that install Energy Star equipment, if Energy-Star rated equipment is available. Exceptions would be water heaters, for which there is no Energy Star rating today (though Natural Resources Canada has started the process to develop an Energy Star rating for water heaters), gas dryers and gas ranges. There are no Energy Star rated water heaters, gas dryers and gas ranges available today.

28.0 Reference: Exhibit B-1, Section 6.5, Conservation Education and Outreach Program Area, p. 65

28.1 Please describe the specifics of the programs outlined in section 6.5.

<u>Response:</u>

These programs have not yet been fully developed, however, as outlined on page 65 of the Application, they are projected to include:

- Stakeholder industry group activities, such as first time homebuyers seminars
- Public outreach by "Team Terasen"
- Support for conservation education within the school system
- Energy Forum
- Conservation communications, as outlined in Appendix 8 in the Application.

29.0 Reference: Exhibit B-1, Section 6.6.1, DSM for Affordable Housing, p. 67

29.1 Please provide the terms of reference or a description of the mandate of the DSM for Affordable Housing Working Group.

Response:

The Terms of Reference for the DSM for Affordable Housing Working Group were finalized during June 19, 2008 monthly meeting and are attached.

Thursday, June 19, 2008

Energy Efficiency for Affordable Housing – BC Working Group

Terms of Reference

Definitions

DSM (Demand Side Management) - demand side management is a method used to manage energy demand including energy efficiency, load management, alternate fuels, and load build[8].

Energy Efficiency - refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity[9].

Low-income - measures of low income known as low income cut-offs (LICOs) were first introduced in Canada in 1968 based on 1961 Census income data and 1959 family expenditure patterns. At that time, expenditure patterns indicated that Canadian families spent about 50% of their total income on food, shelter and clothing. It was arbitrarily estimated that families spending 70% or more of their income (20 percentage points more than the average) on these basic necessities would be in "straitened" circumstances. With this assumption, low income cut-offs have been updated yearly by changes in the consumer price index[10].

Fuel Neutral Approach - a fuel neutral approach treats all fuels equally and does not give preferential treatment to one fuel over another. A fuel neutral approach does not mandate fuel use or provide unbalanced subsidies for different types of energy. Regulations set in this context allow all contenders to compete on a level playing field, provided they meet environmental performance requirements. In a National Energy Policy, fuel neutrality applies to many different issues, including R&D, taxes, land access, and application of environmental standards.

---

8 Source: www.noresco.com/site/content/info_glossary.asp
9 Source: http://www.pplweb.com/glossary.htm
10 Source: http://www.toronto.ca/wards2000/profile_glossary.htm

Low-Income Cut-Offs (LICOs) - The LICOs are published by Statistics Canada. Persons and families living below these income levels are considered to be living in "straitened" circumstances. There are 35 different LICOs, varying according to family size and size of community. The LICOs are more popularly known as Canada's **poverty lines**[11].

Energy Efficiency for Affordable Housing – BC Working Group

Terms of Reference

- The Energy Efficiency for Affordable Housing Group (EEAHG) will focus on facilitation and information sharing to encourage collaboration and coordination provide general advice and comment on related policies and programs as well as work to minimize duplication and identifying gaps around multi-stakeholder fuel neutral programming that is focused on energy efficiency improvements for lower income households.

- This group will focus on reducing energy consumption and encouraging energy efficient behaviour in low-income households in BC through identifying existing challenges and barriers, and areas for collaboration; however, this group will not address larger energy affordability issues. The life-span of the group will commence on December 1, 2007 and continue until December 1, 2009; the goals and group's purpose will be reviewed upon completion of this term.

Membership

Membership in the group is voluntary. The members of the group include the following organizations: MEMPR, Office of Housing and Construction Standards, BC Non-Profit Housing Association, BC Public Interest Advocacy Centre, CMHC, BC Housing, City of Vancouver, City Green, the Terasen Utilities, BC Hydro, FortisBC, NRCan, Homeworks, BC Association of Apartment Owners and Managers (BCAOMA.), Fraser Basin Council, Active Support Against Poverty, and Indian and Northern Affairs Canada and Aboriginal Housing committee (BC Region).

---

[11] Source: Prepared by the Canadian Council on Social Development using Statistics Canada's Low Income Cut-Offs, from *Low income cut-offs for 2004 and low income measures for 2002* Catalogue # 75F0002MIE2005003[11].

30.0 Reference: Exhibit B-1, Section 6.2.2, Support for Audits for a Provincial Home Retrofit Program, p. 67

Terasen states that "one possible area of joint activity for the Companies and the Ministry would be for the Companies to fully or partially fund the post-audits required for the Companies' customers to be able to claim the federal retrofit incentives available.

30.1 How many audits does Terasen estimate it might complete in one year and what is the cost to Terasen for each audit? What is the amount budgeted in each year for TGI and TGVI for this program.

Response:

A budget has not yet been established for post-audits for Terasen Utilities' customers participating in the LiveSmartBC/ecoEnergy programs. Since the LiveSmartBC program has just been introduced to the marketplace, the Companies have yet to determine the level of customer participation in the program, or the funding requirement for post-audits, and consequently cannot set a budget for this activity at this time.

30.2 Would the audits be available to non-Terasen customers? If not, why not?

Response:

The audits are a requirement for participants in the LiveSmart BC program (which is the name of the Provincial Home Retrofit program referred to in the question) to receive the LiveSmart BC incentives. The Companies would not fully or partially fund post-audits for non-Terasen customers, however, as the Companies would not use natural gas ratepayer funds to reduce consumption in non-customer households.

30.3 To what extent has Terasen discussed co-funding the audits with BC Hydro, and/or Fortis BC, and/or the Ministry of Energy Mines and Petroleum Resources, and what is the status of any such discussions? How much would the amount budgeted for the program increase or decrease if co-funding is available or not?

Response:

The Terasen Utilities have had high-level discussions with representatives of the Ministry of Energy Mines and Petroleum Resources about participating in LiveSmart BC. The Companies are awaiting a decision on the EEC Application before furthering discussions.

31.0 Reference: Exhibit B-1, Section 6.2.2, Community Action on Energy Efficiency, p. 68

31.1 Who are the members of the program committee for the Community Action on Energy Efficiency initiative? Is the policy manual available?

Response:

CAEE program includes Ministry of Energy Mines and Petroleum Resources, Ministry of Environment, Ministry of Community and Aboriginal Services, Fraser Basin Council, the Terasen Utilities, FortisBC, Community Energy Association and BC Hydro. More information on Community Action on Energy Efficiency can be found here:

http://www.bcclimateexchange.ca/index.php?p=caee

31.2 What are eligible projects for which municipalities can apply?

Response:

Please view the website provided in the response to BCUC IR 1.31.1 for more information about Community Action on Energy Efficiency.

31.3 What is the amount budgeted in each year for TGI and TGVI for this program?

Response:

The Companies have not yet budgeted an amount for CAEE as the amount that the Companies make available to this program will be dependent on the results of the latest CAEE "Call for Proposals", administered by the Fraser Basin Council. The Companies will make a determination after the latest round of CAEE funding is awarded as to the opportunity and need for contributions from the Terasen Utilities.

32.0 Reference: Exhibit B-1, Section 6.2.2, Trade Relations Program Area, p. 68

The Application states that the funding being requested for Trade Relations ($1.5 million) will support the activities of a Terasen staff member focused on Trade Relations as it relates to energy efficiency.

32.1 Is the staff member salary included in the $1.5 million?

Response:

Yes, salary for one staff member is included in the $1.5 million.

32.2 Is the staff position currently a Terasen position? If not, who manages trade relations for the Companies currently?

Response:

No, the Companies do not have staff currently dedicated to trade relations. Trade relations are handled indirectly by different roles, including Marketing and Energy Efficiency staff, Technical Sales Support staff, and Residential and Commercial Account Managers. The scope of Trade Relations activity needed to support the proposed EEC activity in this application is much greater than could be handled by the Companies' existing resources. The scope requires a dedicated resource as the Companies have proposed.

32.3 Please provide a breakdown of the $1.5 million.

Response:

The Companies are requesting $500,000 per year for Trade Relations activity ($1.5 million in total for the three years). This estimate includes the anticipated cost for a staff member, plus costs for the activities outlined on pages 68 and 69 of the Application. The expenditure proposed is an estimate; work needs to be done on program area development similar to the work that was done to develop the activities and amounts proposed for the Energy Efficiency, Fuel Switching and Communications and Outreach areas. However, in order to start program development in the Trade Relations program area, the Companies are of the view that this is a reasonable and appropriate level for the development of Trade Relations programs. If an appropriate program cannot be developed for Trade Relations, the $500,000 per year proposed would be reallocated to another program area.

33.0 Reference: Exhibit B-1, Section 6.9, Innovative Technologies, p. 69

The Application states that the amount for Innovative Technologies, NGV and Measurement will need to be refined – if an effective program in Innovative Technologies, NGV and Measurement can be developed over the funding timeframe, the Companies wish to have the ability to fund such a program over the funding timeframe.

33.1 Please confirm that Terasen is asking for approval in the Application for spending levels of $500,000 per year for each of 2008, 2009 and 2010 for TGI and TGVI combined for each of the residential and commercial sectors. Please provide the detailed budget estimate behind the requested amount. Is this program properly described as research and development?

Response:

That is correct. A detailed budget has not yet been developed for Innovative Technologies, NGV and Measurement. As noted on page 69 of the Application:

> *"The amount and activity for Innovation Technologies, NGV and Measurement will need to be refined…"*

This program area is more accurately defined as supporting commercialization of newer technologies such as solar thermal water pre-heating than research and development.

The expenditure proposed is an estimate; work needs to be done on program development similar to the work that was done to develop the activities and amounts proposed for the Energy Efficiency, Fuel Switching and Communications and Outreach areas. However, in order to start program development in the Innovative Technologies, NGV and Measurement program area, the Companies are of the view that this is a reasonable and appropriate level for the development of Innovative Technologies, NGV and Measurement programs. If an appropriate program cannot be developed for Innovative Technologies, NGV and Measurement, the $500,000 per year proposed would be reallocated to another program area.

33.2 What criteria will Terasen use to determine if a program in this area is an effective program?

Response:

As outlined on page 84 of the Application, the Companies would use the three-year funding envelope requested to run pilot programs to develop a better understanding of the costs and benefits of new technologies, and from that information would develop cost-effectiveness criteria.

33.3 What level of expenditure does Terasen estimate it would require to review conceptually and to examine programs in Innovative Technologies, NGV and Measurement to determine if effective programs could be developed?

Response:

Section 6.9 of the Application provides an overview of potential areas of opportunity for innovative technology funding. As this would be a new venture for the Terasen Utilities, program and project review human resource hours would be estimated at one full-time person, or approximately $100,000 fully loaded for a staff member.

33.4 If an effective program was not developed over the funding timeframe, what amount of expenditures would be captured in the TGI and TGVI revenue requirements for each year?

Response:

Assuming the Application is approved, the Companies anticipate that staff member time for program development would be included in the deferral account with the amortization included in annual revenue requirements.

33.5 Could Terasen conceptually examine programs in this area and, if an effective program could be developed, apply for funding? If not, why not?

Response:

Conceptually this is an option; however the Companies see this as being inferior to the option proposed with the Application. As noted on page 51 of the Application, in order to reduce the administrative burden and eliminate the need for a further application, the Companies are proposing that the Commission approve the overall expenditure level by utility, rather than approving the funding by program area or by individual program initiative. This maximizes value for ratepayers by keeping the administrative costs associated with regulatory filings down. The initiatives being proposed for the Innovative Technologies, NGV and Measurement program area could be pilot programs, of a limited duration, which typically require fairly quick turnaround times. These would be developed in conjunction with various market actors, including suppliers, installers and builders and developers. These market actors are busy with their core businesses; getting their attention to assist with developing a program that may or may not come to fruition dependent on whether funding was approved or not would be challenging.

The Terasen Utilities have included in the Application accountability mechanisms that make the approach outlined in the question unnecessary. The Companies propose to report out on EEC activity yearly. Further, the Companies propose to engage an EEC stakeholder group; one of the roles for that group would be to ensure that programs that are developed have value for ratepayers. Please refer to pages 88 and 89 of the Application for more discussion on the role of the Stakeholder group.

33.6 Please describe why the Companies' are in a unique position to foster and further the deployment of forward-looking low carbon technologies, and in particular contrast this to the position of a natural gas marketer and a producer.

Response:

The Companies have the primary relationship with customers i.e. with end users, and therefore are in a unique position in terms of communicating with the largest number of natural gas consumers. All of the Companies' customers receive a bill once per month, and this is one of the primary avenues that the Companies use to communicate with customers in the form of bill messages, bill inserts and newsletters. There are multiple gas marketers in the marketplace, none of whom have contact with all natural gas customers. The Companies offer a highly cost-effective way to reach the largest number of prospective participants (being natural gas consumers). Natural gas producers do not provide service directly or communicate directly with end-use natural gas consumers.

34.0 Reference: Exhibit B-1, Section 6.9.1, Innovative Technologies, pp. 71-72

34.1 Please compare the Integrated Energy Systems to the Solar Thermal program in terms of cost/GJ saved and cost per tonne of CO2e saved.

Response:

Table: Integrated Energy System & Solar Thermal DHW Comparison

	Standard Water Heating Load 60% Efficiency / GJ	90% efficient model used for IES System	GJ's Saved	Capital Cost Est Water Heating	Cost per GJ (based on 10 yr life)	Cost per tonne of CO2e
Integrated Energy System	25	16.7	8.3	$ 1,647	$ 20	$ 412
	Standard Water Heating Load 60% Efficiency / GJ	**Solar Fraction 0.5**	**GJ's Saved**	**Capital Cost Est Water Heating**	**Cost per GJ (based on 25 yr life)**	**Cost per tonne of CO2e**
Solar Thermal Program	25	12.5	12.5	$ 8,000	$ 26	$ 533

34.2 The Application states that the Companies would consider providing incentives of $500 towards solar pre-piping as long as a gas hot water tank in installed.

34.2.1 What analysis must be completed or what criteria must be satisfied for the Companies to decide whether or not to provide the incentives?

Response:

In order to provide an incentive for solar pre-piping the Companies would need to review, establish and approve design criteria for several piping/control schematics. The Terasen Utilities would need to establish criteria to satisfy that gas was being used for the fraction of heating not supplied by solar and confirm that $500 is a reasonable incentive amount given these criteria, energy savings and costs.

34.2.2 Why do the Companies propose to limit the incentives to customers who install a gas hot water tank?

Response:

The Companies propose to limit the incentives to customers with a gas hot water tank as this is a measure that conserves energy in the production of hot water. Since the funding for any incentive program would come from natural gas ratepayers, the Companies believe it is appropriate that funding to be directed to natural gas conservation measures, in this case, to the conservation of natural gas used to produce hot water.

35.0 Reference: Exhibit B-1, Section 6.9.1, Fuel Substitution Initiatives, p. 75

The Companies state that they feel there may be an opportunity to invest in several biogas projects over the next few years which would supplement the distribution systems with renewable fuels, thus displacing natural gas by the amount of biogas accepted into the distribution system.

35.1 Is there a cost difference between manufacturing 'distribution system quality' biogas and biogas that would be used directly to, for example, fuel a boiler?

Response:

Yes, there is a cost to upgrade raw biogas to "distribution system quality" as opposed to using it directly in a boiler. However, in order to make use of the biogas through direct use there must be a demand for the energy close to the production site. Injecting it into utility distribution infrastructure allows the gas to be transported to end users if there is not a demand for the energy at or near the production site. Depending on the characteristics of the biogas production, the "distribution system quality gas" can be manufactured at a cost that is competitive with current forward natural gas prices.

35.2 Would investment by the utility in manufacturing 'distribution grade' biogas potentially compete against other commercial projects that could use the biogas directly?

Response:

It is unlikely that investments in manufacturing "distribution grade" biogas would compete with direct use projects. The added cost of the upgrading process would likely prevent an economic business case to upgrade biogas to distribution grade rather than use it in a direct use application if there was a need for energy at or near the production site. For example at the Metro Vancouver Lions Gate Wastewater Treatment Plant, Metro Vancouver uses biogas as fuel for their boilers and is working with Terasen Gas to upgrade the surplus biogas above the plant's operational needs.

35.3 Would it be either TGI or TGVI that invested in the biogas projects or subsidiaries and, if TGI or TGVI, would the project stay within the utility? If not, why not?

Response:

Biogas project investment will be determined on a project by project basis.

36.0 Reference: Exhibit B-1, Section 6.9.3, NGV – Natural Gas Vehicle Projects, pp. 75-76

36.1 Please confirm that that the vehicle grants are existing programs? Are any changes being proposed to the current NGV programs? If so, what changes are proposed?

Response:

The vehicle grants are existing programs. No changes are being sought to existing programs. The requests in the application are for additional funding related to NGV.

36.2 What specific funding level is being proposed for the Hydrogen / Compressed Natural Gas blended project area?

Response:

The initiatives listed in Section 6.9 of the Application do not include all the innovative technologies that the Companies may support, but rather provide an overview of the types of initiatives the Terasen Utilities are aiming to promote that all have the same underlying characteristics; 1) they promote the efficient use of natural gas through sustainable design 2) are not currently mainstream technology 3) offer at a minimum a GHG benefit.

Hydrogen / Compressed Natural Gas blended projects (HCNG) represent one of the most near-term opportunities for utilizing hydrogen in vehicles and moving towards a hydrogen economy. As hydrogen burns cleaner than natural gas, further emission reductions are gained and 10-20 % GHG reductions achieved.

The Terasen Utilities see participation in this field as a viable choice for promoting cleaner burning natural gas vehicles. The Companies have not yet developed a budget specifically for HCNG projects. As the Companies move forward with the identification and prioritization of various opportunities it will determine what resources are required for specific initiatives such as HCNG.

37.0 Reference: Exhibit B-1, Section 6.9.5, Measurement, p. 77

In discussing the residential market, Terasen states that "A reduction in energy use of 20-30% in multi-family developments can result from enhanced visibility and individual energy measurement with the installation of individual meters."

37.1 Please provide all documents and studies underlying the statement that a reduction in energy use of 20-30% in multi-family developments can result from enhanced visibility and individual energy measurement with the installation of individual meters.

Response:

Please see Attachment 37.1:

- Study prepared for Natural Resources Canada, Background Report for the Preparation of a Canadian Standard on Thermal Energy Meters for Hydronic Heating / Cooling Systems, April 2005 – 20-30% energy savings; and
- Article from DBDH, Installation of meters leads to permanent changes in consumer behavior, March 2006– up to 30% energy savings.

37.2 In what types of applications in multi-family developments would gas use not be individually metered? What percentage of all multi-family dwellings with gas service are those? What percentage of all residential accounts are those?

Response:

The types of applications in multi-family developments where gas use would not be individually metered are as follows:

1. Common area space and water heating, including amenities (pool, spa, gym etc).
2. Multi-family developments where there is small gas load in the individual unit may not justify individual metering (i.e. Only one gas appliance such as a fireplace).

The Companies do not have detailed historical information related to all of its multi-family building. However, of the customer attachments made in 2007 by the Companies, approximately 70% of multi-family buildings are attached with a single meter which measures the premises common gas load as well as the individual premises. This represents approximately 40% of total residential customer attachments in 2007.

.

37.3 The Application states that the Companies would consider providing an incentive for builders and developers of $100 per suite to install individual meters or thermal metering to cover the cost of added fittings, valves and promote the use of energy measurement.

Please summarize recent changes to the definition of a service line in multi-family complexes and the rationale for the change. Why does Terasen believe that an additional $100 incentive per suite is necessary or beneficial?

Response:

The definition of a service line for a multifamily unit changed to include an additional sentence as part of the definition as highlighted below to:

> Service Line - Means that portion of Terasen Gas' gas distribution system extending from a Main or a Service Header to the inlet of the Meter Set. In the case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.

As noted in the Application submitted to the Commission on November 2, 2007 and approved by Commission Order No. G-6-08, Terasen stated that:

> *"the Company has started to accept a third approach to providing Service to Premises within Vertical Subdivisions, …In this approach, the Company will install meters in the most appropriate location for the particular Vertical Subdivision, which typically will be a meter closet similar to that described in the first approach. The Company will then install piping to the Premises. This approach is undertaken in cases where the developer is not able to make space available to put the meter at the exterior wall of the individual Premises, but is able to make space available for a meter closet. In effect, Terasen Gas installs the Service Line to the Premises and installs the Meter Set part way along the Service Line. Developers are indicating a preference for this approach as it does not force them into a less cost effective design simply to defray some of the piping costs."*

By making this change to the Tariff, the Company hopes to encourage developers to use gas when they might not make the choice for gas because of increased capital costs.

In all cases a multifamily unit must have a main extension test performed to determine their viability. If the test if positive the main and services are installed. If the test is below the threshold PI of 0.8, a contribution would be required prior to the customer receiving service. However, while the customer/developer may not pay a contribution for the main and service, installing individual meters or thermal meters often results in extra costs for the developer that can not be recovered from home buyers. Increased costs include gas piping, meter closets and associated reduction in saleable square footage, and hydronic heating piping. As noted in the Thermal Meter application, it has been shown that individual metering reduces consumption by up to 30%. Due to these extra costs incurred, developers are less likely to install individual metering or thermal meters even though the end user may appreciate the benefit and the energy consumption of the building would be reduced, thus meeting BC Energy Plan objectives. The Companies are of the view that providing an additional incentive to the developer would help encourage the adoption of individual metering and thermal.

37.4 Terasen's Thermal Metering pilot program was approved by Commission Order No. G-65-07. The Order requires Terasen to report on the status of the program by July 15th of each year, commencing in 2008. Please confirm that Terasen will be submitting its first report by July 15, 2008.

Response:

Confirmed.

38.0 Reference: Exhibit B-1, Section 6.10, The Industrial Sector, p. 78

The Companies state that in the event that the Application is approved, the Terasen Utilities intend to establish an industrial customer EEC working group.

38.1 If the Application is not approved would Terasen convene the industrial customer EEC working group in any event? If not, why not?

Response:

The convening of the industrial customer working group would be dependent upon the decision of the EEC Application. If the Application is not successful in its entirety, it is unlikely that the Terasen Utilities would convene the industrial group. It is likely that certain elements of an approved EEC would be used to set the framework for an industrial program; without approval of the EEC it would make an industrial energy efficiency application redundant and as such convening an industrial customer working group would be moot. However, if the Application is approved in part, depending upon that approval and the conditions therein, the Terasen Utilities may convene the industrial customer working group.

38.2 What amount of the total EEC budget on a year by year and utility-specific basis is allocated to the industrial customer EEC working group? How many of the proposed additional staff would be allocated to this activity?

Response:

There is no budget specifically allocated to the industrial customer EEC working group.

38.3 Do the Companies currently engage in any industrial customer EEC activities? If so, please describe them? Are there any other industrial EEC working groups operating in the province, of which Terasen is a part? If so, how would Terasen's proposed EEC working group supplement other established working groups?

Response:

No, the Companies do not engage in industrial (Rate Schedule 22, 22A, 22B and 27) EEC activities. The Terasen Utilities are involved in the MEMPR led industrial efficiency working group. Information gained and shared through this group could form the basis for industrial efficiency programs.

39.0 Reference: Exhibit B-1, Section 6.11, Staffing, p. 79

The Application states that the increased EEC activity will require increased staffing and that the increased staffing costs are included in the $56.6 million of EEC expenditures for which approval is being sought in the Application.

39.1 Would the costs of the increased staffing levels be capitalized? Are any current staff costs capitalized?

Response:

It is proposed that all incremental funding for EEC activity be capitalized by way of a regulatory asset deferral account, including incentives and costs such as costs for increased staff. Today, the Companies' capitalization policy is that costs associated with the acquisition and construction of capital assets are generally capitalized including any internal labour costs directly related to the construction of the capital asset. A portion of indirect costs are allocated to capital under the Companies' overhead capitalization policy. Staff costs associated with the current level of EEC activity that exists within the Companies today are treated as O&M.

39.2 Table 6.11 identifies the proposed staffing levels, in Person Years by year.

39.2.1 Please identify the proposed staffing levels by Utility by year.

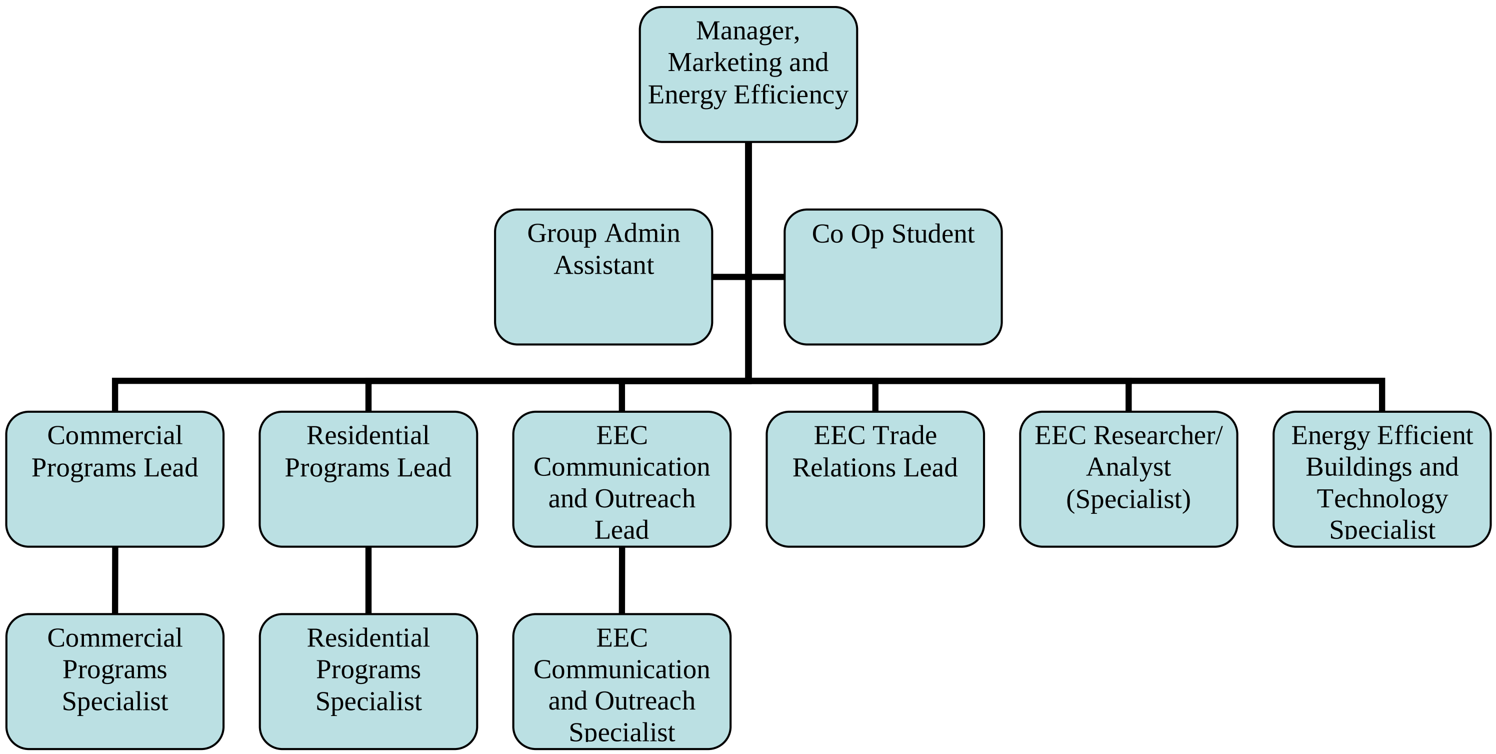
Response:

If the EEC Application is approved as written, staff activities would not be dedicated to a particular Utility, which is consistent with the common management team and shared services approach currently employed by the Companies. Rather they would be responsible for specific program areas that would apply to both Utilities, as outlined in the diagram below. Please note that the diagram reflects the proposed staffing levels at the Companies in the first year of expanded EEC activity. Staffing levels would be adjusted in subsequent years such that as programs expand, additional staff could be added. As well, the services of outside consultants would be used in program development and evaluation. Staffing needs in future years are outlined in Table 6.11 referenced in the IR. The Companies propose that staff costs would be proportionally allocated to each Utility to align with proportional expenditure for incentive and non-incentive costs for each Utility. The breakdown in the EEC Application is approximately equivalent to 80% of expenditures to TGI and 20% of expenditures to TGVI.

Three of the positions are currently funded to 2009 in the DSM program expenses, as per the Settlement Agreement for TGI. The other positions would be funded out of the incremental funding requested in the Application, which funding would be capitalized as proposed. After 2009, the Companies propose that all EEC staff costs be capitalized to be consistent with the proposed financial treatment for all EEC expenditures. The staffing outline above is a reorganization of the Marketing and Energy Efficiency department as it exists today, reflecting the much greater levels of EEC expenditure and activity should the Application be approved.

STAFFING PLAN

ENERGY EFFICIENCY AND MARKETING GROUP



39.2.2 Please identify the specific program areas and activities of the increased staff in the Program Operations group.

Response:

Please refer to the response to BCUC IR 1.39.2.1.

39.2.3 Please provide a table showing the dollars associated with each utility and each program area for each year.

Response:

Total proposed EEC dollars per program area by utility by year can be found in the Application in table 6.2a on page 50 of the Application. The same staff members will be working on various program areas for both utilities. The Companies propose to allocate staff costs between TGI and TGVI on the same basis as the other "portfolio level" costs are allocated - 80% to TGI and 20% to TGVI. However, if the Companies find that staff are spending more than 20% of their time on TGVI, this allocation would be adjusted accordingly.

40.0 Reference: Exhibit B-1, Section 6.12, Financial Treatment for EEC Expenditures, p. 80

40.1 The Application states that allocation of EEC costs to customer classes will be done in a manner consistent with the current practice for each utility. Please summarize the current allocation method for each utility.

Response:

Historically, DSM costs in previous rate design applications have been allocated in the following manner:

TGI DSM costs have been allocated to all customers based on the customers' class coincident peak day demand (BC Gas Inc. 1993 Phase B Rate Design, BCGUL 1996 Rate Design and BCGUL 2001 Rate Design). For annual revenue requirement changes related to delivery margin any revenue deficiency or surplus is allocated to customers on an equal percentage basis.

For TGVI the amortization of DSM costs has been allocated to Distribution customers while the unamortized costs included in the deferral account are allocated to customers in the same proportion as the Transmission and Distribution gas plant have been allocated.

40.2 The Application refers to appliance and energy system installations with a weighted average measurable life of 22.5 years. Please provide a table or spreadsheet showing how the weighted average measurable life of 22.5 years was derived.

Response:

Please refer to Attachment 40.2.

41.0 Reference: Exhibit B-1, Section 6.12. Financial Treatment for Energy Efficiency and Conservation Expenditures, pp. 80 - 82

On page 80, the Application states:

> "The Terasen Utilities propose that the incremental EEC expenditures and existing incentive amounts in TG PBR Extended Settlement and TGVI RR Extended Settlement (TG - $1.5 million and TGVI - $.650 million) be treated in the same manner by charging them to a regulatory asset deferral account on a tax-adjusted basis, the balance of which is amortized over twenty years, with amortization commencing the year following the year in which the expenditure is made. Proposed EEC expenditures will be recovered from the customers of each utility based on the expenditures incurred by each utility. Allocations of costs to customer classes will be done in a manner consistent with current practice for each utility. The change in amortization period will smooth the impact to rates from the proposed increase in expenditure. The twenty year period is more representative of the benefit received by customers from the EEC expenditures resulting in appliance and energy system installations with a weighted average measurable life of 22.5 years. Many of the measures proposed have equipment lives of greater than twenty years, the Companies believe that it is reasonable to expect that the savings from the measures proposed in this Application will persist for at least twenty years, thus the twenty year amortization period was selected."

41.1 Assuming a $1 million DSM expenditure in 2008 that is capitalized, please calculate the detailed annual revenue requirement under the TGI existing amortization methodology until the year it is fully amortized. Include the sum totals at the end of the schedule and segment the earned return between interest and return on equity. Provide a working model in electronic format.

<u>Response:</u>

Attachment 41.1 contains a working model in electronic format. A summary of the results is provided in the following table.

TERASEN GAS INC.
RATE BASE / COST OF SERVICE
DEMAND SIDE MANAGEMENT
CURRENT METHODOLOGY $000's

Particulars		1 2008	2 2009	3 2010	4 2011	Total
Rate Base - Deferred Charge						
Opening, Balance		$ -	$ 690	$ 460	$ 230	
Additions		1,000	-	-	-	
Tax Adjustment		(310)	-	-	-	
Net Additions		690	-	-	-	
Amortization Expense # of Years	3	-	(230)	(230)	(230)	
Closing, Balance		$ 690	$ 460	$ 230	$ -	
Deferred Charge - mid-year		$ 345	$ 575	$ 345	$ 115	
Cost of Service						
Amortization Expense		$ -	$ 230	$ 230	$ 230	$ 690
Income Tax Expense		5	106	98	89	297
Earned Return on Debt		15	26	15	5	62
Earned Return on Equity		10	17	10	3	42
Earned Return on Rate Base		26	43	26	9	103
Total Cost of Service		$ 30	$ 379	$ 354	$ 327	$ 1,091
Present Value Cost of Service @ RORB	7.48%	$ 887				
Discount Rate @ RORB after tax		6.09%	6.14%	6.18%	6.25%	
Present Value of Cost of Service @ RORB after tax	$ 918	$ 29	$ 336	$ 296	$ 257	

The present value of the Cost of Service for 21 years (first year incurred plus twenty years of amortization) at a discount rate of 7.48% is $823 thousand and at the corresponding after tax discount rate is $899 thousand (refer to the response to BCUC IR 1.41.2) These present values of the cost of service for 21 years are less than the present value of the Cost of Service for 4 years (in the table above). Although customers will nominally pay more money over a longer recovery period, but when the time value of money is taken into consideration between a four year period and a 21 year period customers are better off with a longer recovery period. The Companies are of the view that amortizing the EEC costs over the longer period of time provides better value to customers, which the Companies believe is supported by calculations included in this response.

41.2 Assuming a $1 million DSM expenditure in 2008 that is capitalized, please calculate the detailed annual revenue requirement under the TGI proposed 20 year amortization methodology until the year it is fully amortized. Include the sum totals at the end of the schedule and segment the earned return between interest and return on equity. Provide a working model in electronic format.

Response:

Please refer to Attachment 41.1 for the working model in electronic format. A summary of the results is provided in the following table. Please also refer to the discussion in response to BCUC IR 1.41.1.

TERASEN GAS INC.
RATE BASE / COST OF SERVICE
DEMAND SIDE MANAGEMENT
PROPOSED METHODOLOGY
$000's

Particulars		1 2008	2 2009	3 2010	4 2011	5 2012	6 2013	7 2014	8 2015	9 2016	10 2017	11 2018	12 2019	13 2020	14 2021	15 2022	16 2023	17 2024	18 2025	19 2026	20 2027	21 2028	Total
Rate Base - Deferred Charge																							
Opening, Balance		$ -	$ 690	$ 656	$ 621	$ 587	$ 552	$ 518	$ 483	$ 449	$ 414	$ 380	$ 345	$ 311	$ 276	$ 242	$ 207	$ 173	$ 138	$ 104	$ 69	$ 35	
Additions		1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Tax Adjustment		(310)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Additions		690	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Amortization Expense # of Years	20	-	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	
Closing, Balance		$ 690	$ 656	$ 621	$ 587	$ 552	$ 518	$ 483	$ 449	$ 414	$ 380	$ 345	$ 311	$ 276	$ 242	$ 207	$ 173	$ 138	$ 104	$ 69	$ 35	$ -	
Deferred Charge - mid-year		$ 345	$ 673	$ 638	$ 604	$ 569	$ 535	$ 500	$ 466	$ 431	$ 397	$ 362	$ 328	$ 293	$ 259	$ 224	$ 190	$ 155	$ 121	$ 86	$ 52	$ 17	
Cost of Service																							
Amortization Expense		$ -	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 690
Income Tax Expense		5	23	22	20	18	18	17	17	17	16	16	16	15	15	14	14	14	13	13	13	12	329
Earned Return on Debt		15	30	28	27	25	24	22	21	19	18	16	15	13	12	10	8	7	5	4	2	1	323
Earned Return on Equity		10	20	19	18	17	16	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	219
Earned Return on Rate Base		26	50	48	45	43	40	37	35	32	30	27	25	22	19	17	14	12	9	6	4	1	169
Total Cost of Service		$ 30	$ 108	$ 104	$ 100	$ 95	$ 92	$ 89	$ 86	$ 83	$ 80	$ 78	$ 75	$ 72	$ 69	$ 66	$ 63	$ 60	$ 57	$ 54	$ 51	$ 48	$ 1,188
Present Value Cost of Service @ RORB	7.48%	$ 823																					
Discount Rate @ RORB after tax		6.09%	6.14%	6.18%	6.25%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	
Present Value of Cost of Service @ RORB after tax	$ 899	$ 29	$ 96	$ 87	$ 78	$ 70	$ 64	$ 58	$ 53	$ 48	$ 44	$ 40	$ 36	$ 32	$ 29	$ 26	$ 24	$ 21	$ 19	$ 17	$ 15	$ 13	

41.3 Please elaborate on intergenerational equity for future customers paying for past expenditures.

Response:

The Companies do not believe that there would be any intergenerational inequity created for future customers by contributing to the recovery of DSM expenditures as proposed in this Application. On the contrary, intergenerational inequity is more likely to be a concern if DSM expenditures were expensed in the year incurred (Please refer to the response to BCUC IR 1.41.10).

Intergenerational equity has to consider not only the point in time in which the cost is made but also the period of time in which the benefits from the cost is realized and how widespread the benefits are to diverse customers. On page 113 of the Application, Section 8.0 Conclusion, the first bullet, reiterates the EEC programs providing "customers access to a wider variety of energy efficiency and conservation incentive programs, assisting them to reduce energy consumption, thereby lowering customer energy bills and reducing the individual and societal impacts associated with energy use". The benefits of the program are not limited to a single year but cover a much longer span of time as well as having an impact on "societal" costs. Since future customers will also benefit it is appropriate for them to contribute to the cost recovery of the program costs which will have been incurred up to twenty years prior.

Capitalization of EEC expenditures is expressly contemplated in the Commission's DSM Accounting Policy, and is done by other BC utilities. The DSM Accounting Policy states, in part:

> *2. Deferred Costs Included in Rate Base and Earning a Return*
>
> *Costs incurred at different stages of program commercialization reflect varying degrees of uncertainty as to beneficial outcomes and shall be deferred according to the following criteria:*
>
> *(a) A significant or material, non-recurring cost shall be deferred and amortized using a rapid writeoff for the purpose of smoothing the impact on rates.*
>
> *(b) <u>Direct program costs, indirect administration costs and allocated overhead, shall be deferred according to the intent of section 3450 - Research and Development, of the Canadian Institute of Chartered Accountants, Accounting Recommendations Handbook. Generally speaking, those criteria treat research costs as expenses and treat as assets, those development costs that have a high probability of achieving net financial benefits.</u>*
>
> *3. Load Building by Fuel Substitution*
>
> *Utilities engaged in strategic load building by fuel substitution may account for this <u>in the same manner as other DSM strategies</u> subject to Commission directions specific to that utility. Changes to this accounting policy may need to*

> *be made following a multi-utility review of the economic evaluation of fuel substitution. [Emphasis added.]*

We note that Section 3450 Research and Development of the CICA Handbook, which is referred to in the DSM Accounting Policy, is being replaced with Section 3064 Goodwill and Intangible Assets, effective January 1, 2009. Section 3064 as it relates to Research and Development expenditures is substantially the same as previous section 3450, and includes the same approach to research (expense) and development (deferral) expenditures. Please refer to the responses to BCUC IRs 1.44.0 to 1.44.2 for further discussion of accounting guidance on EEC expenditures.

Please refer to the response to BCUC IR 1.10.2 for further information on capitalization.

41.4 Please elaborate further on the current allocation methodology of DSM costs charged to customer classes for each of TGI and TGVI.

<u>Response:</u>

Please refer to the response to BCUC IR 1.40.1.

41.5 Please discuss the merit of a DSM rider charged to customers.

<u>Response:</u>

Whether the charges for DSM expenditures are embedded in the delivery rates or set out separately in a rider they can be allocated to and recovered from the rate classes in keeping with the methodology approved by the Commission. The Companies do not favour using a DSM rider since employing that approach will tend to proliferate the number of line items on the bill and make the rates more complex and confusing to customers. The regulatory processes in which DSM expenditures and charges in rates are reviewed such as revenue requirements, annual reviews, rate design and compliance reporting provide a suitable framework to confirm that DSM costs are being recovered appropriately.

41.6 Please discuss the merit of streaming DSM costs to the specific rate classes of the targeted customers that receive the benefit.

Response:

As discussed in response to BCUC IR 1.41.3, the benefits of the EEC program costs extend beyond the targeted rate class customers to whom the expenditure is made for thus it would be appropriate for a broader group of customers to contribute to the cost recovery for the duration in which the benefits are expected to last. The issue of allocating Demand Side Management costs was to the subject of a study, "Cost Allocation for Electric Utility Conservation and Load Management Programs", prepared by Paul A. Centolella, Steven A. Mitnick, Dr. Barbara Barkovich, Katherine Yap and David Boonin for Oak Ridge National Laboratory Energy Division (1993) and published by the National Association of Regulatory Utility Commissioners (NARUC) in which they had discussed current practices, at that time, and theoretical underpinnings on how costs should be allocated. The authors expressed the view that all customers (in the broad context) who benefit from the expenditure made should be contributing to the cost recovery, not just those customers to whom the expenditure was targeted to.

41.7 Please elaborate on and provide the source calculation of the 22.5 years weighted average life.

Response:

Please refer to the response to BCUC IR 1.40.2.

41.8 By taking into account a change in mix of DSM programs, what are the expected life benefits of the future programs contemplated by TGI and TGVI?

Response:

The expected life energy reductions (benefits) from the mix of program areas that the Companies are proposing in the Application were provided in response to BCUC IR 1.1.1.

41.9 What have been the annualized burner tip price changes for each of the last five years for TGI? Please elaborate on what would be the maximum annual burner tip price increase that customers would be willing to accept.

Response:

The annualized burner tip price changes for TGI residential customers for the last five years are as follows:

Rate Change Effective Date	Annualized Burner Tip Bill *(based on annual usage of 110 GJs)*	Burner Tip Price Changes ($/GJ)	% Change
April 1, 2003	$1,340	$12.18	16%
January 1, 2004	$1,235	$11.22	-8%
July 1, 2004	$1,288	$11.71	4%
January 1, 2005	$1,281	$11.65	-1%
July 1, 2005	$1,353	$12.30	6%
October 1, 2005	$1,533	$13.94	13%
January 1, 2006	$1,527	$13.88	0%
April 1, 2006	$1,348	$12.26	-12%
January 1, 2007	$1,374	$12.49	2%
October 1, 2007	$1,293	$11.75	-6%
January 1, 2008	$1,344	$12.22	4%
February 1, 2008	$1,344	$12.22	0%
April 1, 2008	$1,491	$13.56	11%
July 1, 2008	$1,655	$15.05	11%

The results of the Residential Customer Price Volatility Preferences Study, conducted in February 2005 by Western Opinion Research Inc. and submitted in the TGI 2005-2008 Price Risk Management Plan, provided an indication of customers' preference for price stability. The study results showed that customers were willing to accept a maximum annual bill increase of 17%, based on those study respondents with an average annual gas bill of over $900. While this survey was conducted solely with Terasen Gas residential customers, it was not representative of all Terasen Gas residential customers and, as such, should only be considered as a guide. It should be noted that residential rate increases greater than 17% burner tip have occurred in the past, prior to the past five years. A residential burner tip increase of 32% occurred on July 1, 2000 and an increase of 27% came into effect on January 1, 2001.

41.10 Since the EEC is targeted at conservation, please discuss the merit of expensing EEC expenditures into rates so that ratepayers receive a more immediate price signal thus achieving further conservation? Please elaborate.

Response:

The Commission's DSM Accounting Policy contemplates capitalization of direct DSM program costs, indirect administration costs and allocated overhead, as well costs associated with load building by fuel substitution. Expensing these costs would be a departure from that policy, and would be different from what the Commission has approved for other BC utilities. Please refer to the response to BCUC IR 1.10.2.

Expensing the EEC expenditures in rates would have a more immediate effect on revenue requirements and rates than capitalizing and amortizing these expenses over time. Expensing may yield a more immediate price signal and possibly trigger some conservation but there are also drawbacks to the expensing approach.

Expensing the EEC Expenditures would not the capture the matching of costs and benefits. The benefits of the DSM programs are expected to persist on average for 22.5 years as noted in the preamble to this series of questions. If expensed, current customers will be paying the full cost of the EEC expenditures and future customers will receive the benefits of the DSM programs without having to bear the costs.

Expensing the EEC expenditures may also cause more rate volatility. The level of EEC expenditures may vary from year to year causing rate increases in some years and rate decreases in others. Rate volatility may have unintended impacts on conservation and customer behaviour by causing temporary responses to the rate change without lasting conservation. In contrast rate stability will permit customers to make more considered and lasting investments in conservation measures.

Natural gas customers are already exposed to rate volatility in the commodity portion, or about two thirds of their bills (unless they have enrolled with a marketer in a fixed rate plan). In addition to matching EEC costs and benefits capitalization of EEC expenditures avoids contributing to the volatility experienced by its customers. Further, immediate expensing of costs exacerbates competitive pressures and increases business risk for the utilities.

42.0 Reference: Exhibit B-1, Section 6.12. Financial Treatment for Energy Efficiency and Conservation Expenditures, p. 80 - Amortization Period – FortisBC Inc.

The FortisBC Inc. Settlement Agreement the 2006 Revenue Requirements and the Multi-Year Performance Based Regulation Plan for 2007 to 2009 in Appendix 1 to Order No. G-58-06 page 10 of 38 states:

> "Program costs up to and including 2005 will continue to be amortized over the existing 8 year period. 2006 and future costs will be amortized in a manner consistent with BC Hydro. Concept development costs will continue to be capitalized. Amortization commences in the year following the expenditure, as currently. DSM expenditures associated with cancelled programs are written off in the year in which the program is cancelled. FortisBC is to file a continuity schedule pre and post changes to the amortization rates."

42.1 Please confirm that FortisBC Inc. amortizes its DSM expenditures currently over a ten year period.

<u>Response:</u>

That is correct, as established in Appendix 1 to Commission Order No. G-58-06, on pages 9 and 10, the FortisBC Inc. Negotiated Settlement Agreement, which states:

> *"The Company proposes to change the amortization period for its DSM expenditures from 8 years to 10 years in aggregate, based on a weighted amortization of individual program lives…Individual programs have lives ranging from 5 to 30 years, wit a weighted amortization period of 11 years.*
>
> *BC Hydro:*
>
> > *a. Amortizes the Power Smart costs to appropriately match the costs with the energy savings benefits, but in any case not to exceed 10 years."*

The Negotiated Settlement Agreement states:

> *"2006 and future costs will be amortized in a manner consistent with BC Hydro".*

The Terasen Utilities are proposing an amortization period of 20 years, based on a weighted average of the proposed measure lives. (It should be noted that the range of measure lives outlined in the Application range from 13 to 25 years.) This is consistent with the practice of the other two large BC Utilities, whose amortization periods approximately mirror the measure lives of the appliances, systems and buildings installed as a result of the expenditure that is being amortized.

42.2 Do the Terasen Utilities write off DSM expenditures associated with cancelled programs in the year the program is cancelled? If not, please explain.

Response:

Currently, funding for DSM programs is approved yearly in the Annual Revenue Requirement. For existing programs, non-incentive program expenditures are currently expensed as O & M in the year in which they are incurred. Currently, incentives associated with programs are treated as laid out in Section 3.2 of the Application, that is, amortized over three years. The Companies propose that should the Application be approved as outlined, expenditures associated with cancelled programs would be treated the same as other expenditures in order to reduce the administrative burden and would be amortized over 20 years.

42.3 Do the Terasen Utilities consider an initiative such as the Efficient Boiler a program or is a program considered to be broader such as the EEC? Please elaborate.

Response:

In the context of the question above, TGI Efficient Boiler program would be a program. In the context of the EEC Application, the Efficient Boiler program would be considered a measure within the Commercial Energy Efficiency program area.

43.0 Reference: Exhibit B-1, Section 6.12. Financial Treatment for Energy Efficiency and Conservation Expenditures, p. 81

On page 81 of the Application it states:

> "Twenty years was selected by the Companies as being a good balance between recognizing the persistence of savings, and keeping natural gas rates competitive with other energy forms by avoiding an excessively short amortization period. Customer rate impacts are discussed further in Section 7.1. A twenty year amortization period is consistent with the Commission's guidelines regarding accounting for DSM expenditures, as per Commission Order No. G-55-95, dated June 29, 1995, that states 'A utility may apply for a normal write-off longer than 10 years'. It is the Companies view that the amortization period of twenty years better matches the cost recovery to the period over which benefits will accrue to customer."

43.1 The January 30, 2006 Summit Blue report entitled "Demand-Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Testing" prepared for CAMPUT states on page 34: "Most utilities and regulators prefer the practice of expensing energy efficiency costs; in the long run, this approach costs less than capitalizing - deferring and amortizing - costs. The only exception is in cases where programs are being started from scratch, and decision-makers are worried about rate impacts. Capitalizing energy efficiency costs from a period of one year to the average lives of the program measures is done in some jurisdictions. This practice does reduce the immediate cost to implement programs, but there are problems. The carrying cost (at the utility average cost of capital, 7-9% these days) of the unamortized balances adds cost to consumers, quite a lot if the amortization period is long. Eventually, consumers are paying each year's amortized balances, which add up to the annual amount spent on efficiency, plus the carrying cost. Utilities are also concerned about increasing "regulatory asset" balances, assets on the utility books not backed by actual equipment. Once this practice starts, it is hard to convert to expensing, again due to rate impact concerns."

43.1.1 Would the Terasen Utilities agree that by capitalizing DSM costs there is an increased cost to the ratepayer over the longer run rather than expensing?

Response:

When the time value of money is considered customers may be better off when the utility recovers the costs, including the utility's carrying cost, over an extended period of time rather than having to recover the cost in the year of expenditure.

The Terasen Utilities believe there are other reasons to capitalize DSM costs and amortize them over a period of time. Please refer to the response to BCUC IR 1.10.2.

43.1.2 What are the benefits to the shareholder for a longer amortization period such as ten and 20 years when compared to the current approved amortization period?

Response:

Whether the DSM expenditures are amortized over a ten-year, twenty-year or the current period, the rate of return for the utilities' shareholder will only be the regulated rate of return on equity that is allowed for each year. By matching the period of amortization to the period of benefit experienced by customers, the rate impact, and thus the competitive pressure, is not as great as it would be under the current amortization period.

43.1.3 If the TGI capitalized the DSM expenditures with an amortization period of 20 years for a number of years until the balance grew to a sizable amount, would it be difficult to revert back to an amortization period of three years without causing rate impact concerns? Please elaborate.

Response:

It would be speculative as to whether or not shortening the amortization period would cause rate impact concerns in the future. Other factors such as changing commodity prices could play a much more significant role affecting rate stability while trying to ensure full cost recovery of the utility's costs.

It would only be appropriate to shorten program costs recovery in the future if the benefits from the future programs were to be realized within a three year period from the time of the expenditure. It is not anticipated that EEC program costs would change from having long term benefits that extend out numerous years. What is more likely to change is the technology, its cost at that time, and the level of demand for new energy conservation devices; all of which at this time would speculative.

Reverting to a shorter amortization period, in the absence of evidence pointing to a shorter duration of benefits, would lead to intergenerational inequity concerns similar to those that would occur in the context of expensing DSM costs as discussed in the response to BCUC IR 1.41.10

43.2 Appendix A to Order No. G-55-95 on page 2 of 3 states in Section 6 Amortization Rates:

"DSM costs that have been deferred shall be subject to the following amortization periods as appropriate:

- Rapid write-off for significant or material non-recurring costs – 2 - 3 years.
- Normal write-off for recurring costs that qualify as assets – 3 - 10 years.

A utility may apply for a normal write-off longer than 10 years."

43.2.1 Please outline and quantify the Terasen Utilities significant or material non-recurring costs in the Application, if any.

Response:

The Terasen Utilities have not assessed the requested EEC funding in terms of whether the costs are recurring or non-recurring. The EEC funding has been separated in terms of whether the costs are related to program costs or to incentive costs. In the Terasen Utilities' view none of the costs in either category would be classified as "significant or material" non-recurring costs. The costs in both the program cost category and the incentive cost category are of an ongoing nature and are aimed at producing the sustained efficiency and conservation benefits being sought in the Application. Consequently the applied-for EEC costs would fall into the normal write-off category. The Terasen Utilities' request for a write-off period of longer than 10 years is predicated on a closer matching of the amortization period with the time period of 22.5 years that the benefits are expected to persist. There are a number of benefits associated with capitalizing EEC expenditures, as described in BCUC IR 1.10.2

43.2.2 Please outline and quantify the Terasen Utilities recurring costs that qualify as assets in the Application, if any.

Response:

Please refer to the response to BCUC IR 1.43.2.1.

43.2.3 What is considered an "excessively short" amortization period?

Response:

The Companies consider an "excessively short" amortization period to be period that is significantly less than the measurable life of the program benefits.

43.2.4 On page 35 Table 3.5 Summary Information Other Utilities DSM Activity of the Application it shows the DSM Funding Treatment: O&M, rate base, and public purpose fund.

43.2.4.1 For these utilities that include the costs into rate base/capital what are the amortization periods.

Response:

Please refer to the response to BCUC IR 1.43.2.4.2

43.2.4.2 For these utilities that rate base its DSM expenditures please provide information on the amounts that are capitalized annually and the amounts expensed, if any.

Response:

The table below provides the details on amortization periods for utilities that include the costs into rate base/capital

Utility Name	Amortization Period	Capitalized vs. expensed
BC Hydro	10 yrs	Capitalized but DSM expenditures associated with cancelled programs are written off in the year in which the program is cancelled
FortisBC	10 yrs	Capitalized
Manitoba Hydro	15 yrs	Expensed but spread over a 15 year amortization period
Union Gas/Enbridge Gas Distribution	n/a	Included in rate base; earn based on an incentive mechanism

Further details for each utility are provided below.

BC Hydro

"Costs are capitalized and amortized to appropriately match the costs with energy savings benefits over future years, not to exceed ten years.

Costs incurred in the concept development phase are not capitalized as there is no assurance that any program will be accepted for development and implementation.

Program-specific and non-specific portfolio development and implementation costs are capitalized and amortized over a period not to exceed ten years. Amortization commences in the year following the year in which the expenditure is incurred. DSM expenditures associated with cancelled programs are written off in the year the program is cancelled. Costs that are not capitalized are expensed as OMG&A in the period incurred."

Source: http://www.bchydro.com/rx_files/info/info45426.pdf, Section 8, p71

DSM expenditure in 2007 was $4.942 million in operating costs and $47.313 in deferred capital.

Source: BC Hydro PowerSmart, "Report on Demand-Side Activities for the Twelve Months ending March 31, 2007"

FortisBC

All DSM expenditures are capitalized, including incentives, labour, expenses including advertising, but none are O&M. About ~10% of the Technical Advisors time is designated as Key Account management and thus O&M. However KAM is for non-DSM matters, so the O&M expense will go to Customer Services.

Also it is the *net* DSM expenditure, after income tax effect (~31%), that is capitalized in rate-base. So a $2.4m nominal spend translates into $1.6m rate base addition.

Source: Email Correspondence, Keith Veerman, FortisBC PowerSense Department.

Manitoba Hydro

The Terasen Utilities had asked Manitoba Hydro to clarify this, below is their response:

None of Centra's[12] DSM costs are capitalized. All of Centra's DSM costs are expensed, but they are spread out over the 15 year amortization period. Manitoba Hydro (the electrical operation) does not earn a return on DSM expenditures because as a crown corporation it is regulated under a cost of service methodology (not rate base/rate of return). Manitoba Hydro's return is based on long term forecasts and rates designed to leave an adequate operating reserve and debt/equity ratio. Return on rate base or like assets is not considered when determining rates. It should be noted that Centra also now regulated under a cost of service methodology but this is very recent and the Manitoba PUB still looks at rate base in Centra's filings and rate base is used as an allocater in its cost of service study.

Source: Email Correspondence, Brad De Ryck, Gas Rates & Regulatory Department Manitoba Hydro.

[12] Centra is the natural gas subsidiary of Manitoba Hydro.

Union Gas and Enbridge Gas Distribution

Both include costs in their rate base, but do not capitalize the expenditure. Uses a Variance Account to reconcile expenditure and revenue at the end of each financial year; neither company earns on the DSM revenue but rather through the SSM mechanism.

http://www.oeb.gov.on.ca/documents/cases/EB-2005-0437/decision-231205.pdf (Section 4 refers to the SSM and Section 6 to the DSMVA).

43.2.4.3 Are the Terasen Utilities aware of any utility that amortizes DSM costs over a 20 year or greater period? If so, please provide the name of the utility and the details of the DSM program.

Response:

Further research failed to uncover any examples where utilities are using or proposing amortization periods as long as 20 years. Note, however, that the 20 year period selected by the Companies is based on estimates of "the life of the assets". There are other instances where utilities have adopted the "life of the asset" approach, but arrived at a different conclusion as to the life of the assets (i.e. a shorter amortization period) in those particular circumstances. The approach is consistent with the Commission's DSM Accounting Policy and the Commission has approved this approach for FortisBC and BC Hydro.

Please also refer to the responses to BCUC IRs No. 1, Questions 10.2, 42.1 and 43.2.4.2. Similarly, the Nevada Administrative Code, NAC 704.9523[13], charges the Public Utility Commission with determining an amortization period that is "consistent with the life of the investment."

43.2.4.4 What is a "public purpose fund" and how is it generally funded? Would a public purpose fund be suitable for the Terasen Utilities?

[13] http://www.leg.state.nv.us/NAC/NAC-704.html#NAC704Sec9523conci

Response:

In general, a "Public Purpose Fund" (PPF) is a mechanism to raise revenues from utility customers for a specific purpose such as DSM, low-income support or the funding of renewable energy resources. The PPF charge typically appears as a separate line-item on the customer bill rather than being rolled into the rates, so it shows up as a rate rider in the utility's tariff. There are different variations on PPFs; in some cases, PPFs fund DSM activity by a central agency. In others, PPFs fund utility DSM activity. More information on this can be found in Appendix 4.

In the case of Oregon, the Public Purpose Fund was established by legislation – by Senate Bill 1149, which was approved in 1999 and which came into effect March 1, 2002. No such statutory basis exists for the Terasen Utilities to fund DSM activity through a PPF – this is one reason that a PPF would not be an appropriate funding vehicle for the Terasen Utilities EEC activity.

In British Columbia, each utility has applied for and managed its own DSM funding according to its particular circumstances and Commission approvals received. British Columbia utilities have also rolled their DSM funding into revenue requirements and rates in keeping with Commission orders. It would not be appropriate for some utilities in the province to be required to fund their DSM programs in the manner of a PPF while others rolled those expenditures into rates. The normal utility regulatory proceedings dealing with revenue requirements, rate design, resource acquisition and compliance reporting provide suitable opportunities to ensure that DSM funding is reviewed, approved and fairly charged in rates. The Energy Plan does not make mention of PPFs, but rather in Policy Action # 3 states that the Ministry will ensure that appropriate incentives are in place to encourage investor-owned utilities to pursue cost-effective DSM programs. The Companies believe that the financial treatment proposed in the Application provides for that financial incentive.

43.2.4.5 Please discuss the pros and cons of the various DSM funding treatments: O&M, rate base, and public purpose fund.

Response:

The pros and cons of the DSM funding treatments in general are discussed below, however in every jurisdiction, nuances in rate-making exist that impact how the pros and cons laid out below would be experienced or not by each individual utility.

O&M:

Pros: The DSM expenditures are recovered in rates in the same fiscal period in which they are incurred so there is no residual to recover in future fiscal periods.

Cons: Expensing the DSM expenditures in O&M does not allow matching of the EEC costs with the DSM benefits produced which will persist over a number of years. Current customers pay for benefits that will be received by future customers.

To the extent there is year to year variability in the level of DSM spending, expensing the DSM expenditures in O&M will introduce rate volatility.

In order to encourage a utility to make DSM expenditures, an accompanying incentive mechanism is needed, which can be more difficult to administer than including expenditures in rate base and amortizing.

Rate Base:

Pros: The DSM costs are amortized in rates over a similar period for which the benefits of the DSM programs are expected to persist.

Rate volatility from varying levels of DSM spending is avoided. Please refer to the response to BCUC IR 1.10.2. The rate impact of the rate base approach is lower initially and is smoothed relative to the expensing approach. In addition, the present value of the revenue requirements from the rate base approach is lower for customers assuming customers have a time value of money preference based on a higher discount rate than the utility's after-tax cost of capital.

Cons: Effect of DSM spending on rates persists into the future with no related tangible assets on the Companies' books

Public Purpose Fund:

Pros: A public purpose fund provides a relatively straightforward and transparent means of raising funds for programs and activities considered worthy of such support.

Cons: A public purpose fund requires the establishment of a separate organization to administer the collection of funds and the carrying out of programs. This has the potential to become bureaucratic and will likely alter the utility-customer relationship in terms of the provision of DSM services. Please refer to the response to BCUC IR 1.43.2.4.4

Please note that, unlike in Oregon, there is no legislative basis for a Public Purpose Fund in British Columbia making this approach impractical. Please refer to the response to BCUC IR 43.2.4.4.

43.2.4.6 Please describe the currently approved DSM incentive mechanism used by Union Gas and Enbridge Gas Distribution in Ontario.

Response:

The OEB has mandated an incentive mechanism, the Shared Savings Mechanism ("SSM"). This incentive mechanism rewards the utility for success in DSM. The utility receives a portion of all societal benefits resulting from the DSM programs. The monies are collected from the customer and are later distributed to the shareholder.

The formula for determining the SSM payout is laid out in the OEB's decision EB 2006-0021. The table below illustrates the shape of the curve that determines the incentive amount paid out to each utility. As the utilities increase their Total Resource Costs ("TRC"[14]) benefits, they have achieved, the payout increases up to a maximum of $8.5 million. This amount will increase annually by the Ontario Consumer Price Index ("CPI") as determined in October of the preceding year (i.e., the 2008 cap will increase based on CPI at October 2007[15]). The indexing target used in the SSM calculation for 2007 for EGD is $150

[14] TRC test is a benefit-cost test which measures the net costs of a demand-side program as a resource option based on the total costs of the program. It is satisfied when the cost of energy saved through DSM is less than the cost of providing the same energy from new supply.

[15] http://www.oeb.gov.on.ca/documents/cases/EB-2006-0021/dec_dsm_250806.pdf

million, and for Union Gas, $188 million. Targets for subsequent years are set according to a formula.

% of Annual Target achieved	**Payout**
Up to 25%	$225,000
Up to 50%	$675,000
Up to 75%	$2,250,000
Up to 100%	$4,750,000
Up to 125%	$7,250,000
Above 125%	$8,500,000 [1]

[1] Savings above 125% are capped at $8.5 million

Current regulatory settlements for both utilities span three years (2007 to 2009).

Please see the Companies response to BCUC IR 1.10.2.

44.0 Reference: Exhibit B-1, Section 6.12, Financial Treatment for Energy Efficiency and Conservation Expenditures, p. 81 - GAAP

On page 82 it states under the topic International Financial Reporting Standards (IFRS):

> "The proposed financial treatment of EEC expenditures is currently permitted under Canadian Institute of Chartered Accountants ("CICA") Handbook section 3062 'Goodwill and Other Intangible Assets'. Effective for 2009, a new CICA Handbook section 3064 'Goodwill and Intangible Assets' will replace section 3062. Under the new section, DSM expenditures are expected to continue to meet the requirements of the Handbook for deferral. Should DSM expenditures fail to meet those criteria, they would qualify for deferral in the GAAP hierarchy under the provisions of SFAS 71 'Accounting for the Effects of Certain Types of Regulation'".
>
> In Exhibit B-5-1 BC Hydro F09/F10 Revenue Requirements Application BCUC IR 1.79.4 the question stated: "Please confirm that under Generally Accepted Accounting Principles ("GAAP"), DSM expenditures are to be expensed and not capitalized." The BC Hydro response was: "Absent a BCUC approval, DSM expenditures would be expensed and not capitalized."

44.1 Please confirm that under current Canadian GAAP without a regulatory approval order DSM expenditures must be expensed in the financial statements.

Response:

Under current Canadian GAAP, Section 1100 Generally Accepted Accounting Principles contains an exemption for rate-regulated operations, which reads as follows:

> *"Pending completion of a separate project on rate-regulated operations, an entity is not required to apply this Section to the recognition and measurement of assets and liabilities arising from rate regulation."*

Therefore, under the current GAAP exemption for rate-regulated operations, as long as there is regulatory deferral treatment for EEC expenditures, the expenditures would be permitted to be deferred. In the absence of that exemption, EEC expenditures would be evaluated under section 3062. Again, under that section, without regulatory deferral treatment the expenditures would be expensed.

44.2 Please explain how DSM expenditures would qualify under Section 3062 (currently) and Section 3064 (in 2009) as an asset. Cite the CICA section and the reasoning. Is the classification as an asset dependent having an explicit BCUC approval for a regulatory asset?

Response:

The classification as an intangible asset is dependent on regulatory deferral treatment. Whether a specific order is required or whether established practice is sufficient, is subject to interpretation of what constitutes a "legal right" under section 3064 paragraph 12.

Current Section 3062 defines an intangible asset as "an asset, other than a financial asset, that lacks physical substance".

Section 1100 further defines an asset.

1100.29 Assets are economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained.

1100.30 Assets have three essential characteristics:

a) They embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows, and, in the case of not-for-profit organizations, to provide services;

b) The entity can control access to the benefit; and

c) The transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

Section 3064 defines an intangible asset as "an identifiable non-monetary asset without physical substance." The definition of an asset in section 1100 is unchanged from above. Therefore, to meet the definition of an intangible asset, there are three essential characteristics that are required to be satisfied - identifiability, control, and future economic benefits. Section 3064 goes on to define these three characteristics as follows:

3064.12 An asset meets the **identifiability** criterion in the definition of an intangible asset when it:
(a) is separable (i.e., is capable of being separated or divided from the entity and sold, transferred, licensed, rented or exchanged, either individually or together with a related contract, asset or liability); or
(b) arises from contractual or other legal rights, regardless of whether those rights are transferable or separable from the entity or from other rights and obligations.

3064.13 An entity **controls** an asset if the entity has the power to obtain the future economic benefits flowing from the underlying resource and to restrict the access of others to those benefits.

3064.17 The **future economic benefits** flowing from an intangible asset may include revenue from the sale of products or services, cost savings, or other benefits resulting from the use of the asset by the entity.

Identifiability:

The Terasen Utilities, through their regulatory construct, has a right to recover the prudent costs of providing services to its customers. The right to collect these amounts is by statute and therefore meets the definition of identifiability (it arises from a legal right).

Control:

The Terasen Utilities have a monopoly on the provision of gas distribution service in their service territories. No other entity has the right, and therefore ability, to access the future economic benefits embodied in the Companies' assets, including its regulatory assets.

Future economic benefits:

Regulatory assets will result in revenues to the Terasen Utilities in excess of revenues otherwise collectible from customers in rates. The future economic benefits are cash flows that recover both the costs embodied in the assets and the cost of financing the assets until the costs embodied therein are fully recovered. The link between the asset and the future economic benefits is direct.

The primary argument against recognition of regulatory deferral accounts as intangible assets is based on the assertion that they are not 'a resource controlled by an entity as a result of past events; and from which future economic benefits are expected to flow to the entity. "*The economic benefits arising from a right to charge a higher price can only flow to the entity as a result of future sales to those customers. The economic benefit from sales to customers should be recognized in accordance with IAS 18 (Revenue), which requires delivery of the goods or services to the customers*". (E&Y, International GAAP 2008, Volume 1, Section 3.1).

The Terasen Utilities would argue that the past event triggering the legal right to future economic benefits is the incurrence of a prudent cost, previously approved for recovery from customers. The sale of gas and collection of those benefits is merely the mechanism for realizing collection of those costs.

Paragraph 3064.17 and paragraph 17 of IAS 38 specifically provide that future economic benefits include revenue from the sale of products and services. All of the Terasen Utilities' assets, not just its regulatory assets, are dependent upon the future sale of gas in order to realize the legal right of cost recovery. And they are all dependent in the same way. In this sense, a regulatory deferral account and a length of pipe in the ground are no different in terms of the future benefits that they embody.

Therefore, the Terasen Utilities are of the view that EEC expenditures, when approved for deferral treatment by the regulator, qualify as intangible assets under Section 3064 of the Handbook, and by default under Section 3062 of the Handbook, since the definition under Section 3062 is less stringent (lacking the requirement of identifiability). Confirmation or rejection of this view by the Company's auditors will be required prior to the first quarter of 2009.

44.3 How do DSM expenditures meet the requirements under SFAS 71 to be classified as an asset? Cite the SFAS 71 passage and provide the reasoning.

Response:

Statement of Financial Accounting Standards No. 71 paragraph 9 states:

> *"Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:*
>
> *a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.*
>
> *b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost."*

By virtue of allowing DSM expenditures to be deferred and recovered from customers over a period of years, the BCUC's actions provide reasonable assurance of the existence of an asset. Where amounts are deferred for regulatory purposes, it is probable that future revenues in the amount of the deferred expenditures will be recovered from customers.

45.0 Reference: Exhibit B-1, Section 6.12, Financial Treatment for Energy Efficiency and Conservation Expenditures, p. 81 - International Financial Reporting Standards (IFRS)

On page 82 the Application states:

> "The Companies are of the view that the proposed financial treatment of EEC funding also meets the requirements of IFRS. If, however, after further discussion and closer examination in conjunction with auditors and other utilities, the EEC funding failed to pass these tests, then the Terasen Utilities will revisit the program to ensure that it continues in a fashion which maintains an alignment on interests between customers, investors and government policy."

45.1 Please explain how the proposed financial treatment of EEC funding meets IFRS requirements. Cite the specific standard and provide the reasoning.

Response:

Background Information:

IFRSs do not contain any specific guidance or exemptions for rate regulated operations. The International Financial Reporting Interpretations Committee (IFRIC) published an IFRIC Update in August 2005. The IFRIC was asked whether US SFAS 71 Accounting for the Effects of Certain Types of Regulation could be applied under the hierarchy in IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors for selection of an accounting policy in the absence of specific guidance in IFRSs. In response to this question, the IFRIC noted that, because SFAS 71 is a US standard, it was not clear whether applying it would always result in accounting that was consistent with all of the relevant IFRSs.

The IFRIC had also discussed the possible recognition of regulatory assets as part of its project on service concessions. As a result of its consideration of the issues at that time, the IFRIC concluded 'that entities applying IFRSs should recognize only assets that qualified for recognition in accordance with the IASB's Framework for the Preparation and Presentation of Financial Statements and relevant accounting standards, such as IAS 11 Construction Contracts, IAS 18 Revenue, IAS 16 Property, Plant and Equipment and IAS 38 Intangible Assets.' In other words, the IFRIC thought that an entity should recognize regulatory assets to the extent that they meet the criteria to be recognized as assets in accordance with existing IFRS. Whether the assets are labeled as 'regulatory' should not affect their recognition.

The IFRIC therefore concluded that any Interpretation would do little more than inform constituents that, when deciding how to account for regulatory assets, they should consider existing accounting standards. In summary, the IFRIC agenda decision does not preclude the recognition of regulatory assets and liabilities. It does require entities to apply existing standards, including the Framework, carefully to items it is considering recognizing and does not permit the automatic application of the requirements of SFAS 71.

Canadian Utility Adoption of IFRS:

The Terasen Utilities have been working closely through the Fortis group of companies with other Canadian utilities and the CGA, CEA and CEPA to present its view that regulated assets do meet the definition of intangible assets under IAS 38.

IAS 38 is identical to new CICA Handbook section 3064, with the exception of the revaluation model that is allowed in IAS 38 but not currently permitted under Canadian GAAP. The requirements of section 3064 are discussed in response to BCUC IR 1.44.2.

Therefore, if the Companies' regulatory assets, including approved deferred EEC expenditures, meet the definition of an intangible asset under section 3064, they should by default meet the definition of an intangible asset under IAS 38.

45.2 Does IFRS allow for rate regulated assets to be created? If so, cite the standard and provide the reasoning.

Response:

Please refer to the response to BCUC IR 1.45.1.

46.0 Reference: Exhibit B-1, Section 6.13, Portfolio Approach to EEC Programs, and Alignment of Program Cost/Benefit Analysis Practices Across the Terasen Utilities, pp. 82-88

In a Terasen Gas letter dated July 5, 2007 to the Commission it stated: "Free rider levels were anticipated and forecast at the time of program development, most of which were developed in 2005. Terasen Gas will be undertaking program evaluations on the Energy Star Heating Upgrade, Residential New Construction and Efficient Boiler Programs in 2007 and a key aspect of the evaluation of these programs will be analysis of free rider levels."

On page 86 of the Application the Terasen Utilities state:

> "Free rider ratios are the subject of great debate as there is no definitive method to determine the number of free riders in a program. The methodology and reporting of free riders is subjective, even when program participants are surveyed regarding a program's influence over their purchase decisions. Free rider rates are notional. Further, the net-to-gross ratio of energy savings from EEC activity is complicated by "free driver" effects. The free driver effect is very difficult to quantify, but it will tend to cancel out the free rider effect."

46.1 Please explain how the free-rider levels were determined in the evaluation of the 2007 DSM programs. Were the free rider estimates based on judgment, empirical studies, and/or market surveys? Is it possible that the estimated free-riders may actually be higher than forecast?

Response:

Please refer to the response to BCUC IR 1.3.5. While it is possible that estimated free rider rates may be higher than forecast, it is also possible that free rider rates may be lower than forecast. For example, the free rider rate for the Energy Star Heating Upgrade program was estimated at 50% but the Evaluation Study (filed in response to BCUC IR 1.71.2) found a free rider rate of only 43%.

46.2 Please find attached as Appendix A the article "Burning Our Money to Warm the Planet: Canada's Ineffective Efforts to Reduce Greenhouse Gas Emissions", C.D. Howe Institute, by Mark Jaccard, Nic Rivers, Rose Murphy, John Nyboer and Bryn Sadownik.

The article on page 7 indicates that many free riders benefit from subsidy programs and noted that the inadequate estimation of free riders by utilities. It also states that programs did not reduce utility sales nearly as much as expected because of free-ridership rates above 60%.

46.2.1 Please comment on the statements made in the article by Jaccard et al. regarding free ridership?

Response:

In addition, please refer to the response to BCUC IR 1.3.1.

Terasen Gas' evaluation study on the Energy Star Heating System Upgrade program, filed in response to BCUC IR 1.71.2, found that although the Companies had estimated the free rider rate at 50%, the free rider rate was lower at 41%, so while it is possible to over-estimate free rider rates, it is also possible to under-estimate them. The fact that there is this variety of analysis results on free riders points supports the view of the Companies that free rider rates are notional, as expressed on page 86 of the Application. As noted in the response to BCUC IR 1.49.4 below, it is the Companies' view that it is the energy consumptions reductions that matter. The comments about free ridership made by Jaccard in his paper should not be taken out of context. Jaccard's work proposes on page 27 that instead of what the paper refers to as "subsidy and information" approaches to energy conservation, alternative policy approaches must be pursued, namely those that legally or financially impede GHG emissions. That is a larger policy question that is beyond the scope of the Terasen Utilities' EEC Application, which is based upon the Government of British Columbia's policies, as outlined in Sections 7.2 and 7.3 of the Application.

46.2.2 Do the Terasen Utilities consider its estimation of free-riders for its programs to be reasonably accurate?

Response:

The Companies believe that the estimation of free riders is no more or less reliable than those of other utilities. Please refer to the response to BCUC IR 1.3.5.

46.2.3 Are the Terasen Utilities aware of any Canadian or American independent studies on free riders on utility programs conducted in North America in the last five years? If so, summarize the findings.

Response:

Please refer to the response to BCUC IR 1.3.1.

46.3 Please provide cite and the provide study reports that analyze and quantify the "free driver effect" in the context of utility DSM programs.

Response:

Please refer to the response to BCUC IR 1.3.1.

46.4 Please elaborate further on the statement that the free driver effect tends to cancel out the free rider effect.

Response:

This should more correctly have been written, "the spillover effect tends to cancel out the free rider effect." There has not been as much work done on spillover as there has on free riders. A paper by William Saxonis entitled "Free Ridership and Spillover" is included in Attachment 46.4. It discusses free rider effects, spillover, the difficulty of estimating them, and the relative impacts of both. It looks at the spillover/free rider results for energy efficiency programs offered by NYSERDA, and finds that "…six out of the ten programs have spillover effects roughly double the free rider rates...". Therefore the additional energy savings activity gained from "spillover" participants cancelled out the reductions in program energy savings from free riders. In fact, some of the NYSERDA programs have a NTG ratio of greater than one.

46.5 Please cite and elaborate on any Canadian utility that includes the "free rider effect" in its calculations for its TRC test or other test.

<u>Response:</u>

Please refer to the response to BCUC IR 1.3.1.

47.0 Reference: Exhibit B-1, Section 6.13, Portfolio Approach and Alignment of Cost/Benefit Analysis, p. 83-84

47.1 The Application states that the Portfolio Level analysis would not include an accounting for energy savings benefits from the Companies' proposed investment in Conservation Education and Outreach, Joint Initiatives, Innovative Technologies, Trade Relations and NGV and Measurement. The Companies propose to monitor the effectiveness of Conservation and Outreach, and Trade Relations through awareness tracking.

How would the awareness tracking be done? Who would do it? How effective is it?

Response:

Advertising Tracking – Approach and Effectiveness

The recommended awareness tracking research for Conservation Education and Outreach would be similar to that conducted for Customer Choice, for which, near continuous advertising tracking (ad tracking) research has been conducted since February 6, 2007.

In 2008, the Customer Choice ad tracking sample sizes were increased to provide more robust results in our Customer Choice research. This allowed for more confidence in short-term data defined by region, or other demographic information. The following summarizes the methodology selected for 2008 Customer Choice research:

- telephone interviews with homeowners, 25 years of age or more
- 90 interviews per week in a two-week, pre-wave or 'ghost' phase
- 300 interviews per week in the initial four-week tracking phase for each new commercial
- 60 interviews per week during other weeks
- interviews evenly divided among Terasen Gas' marketing regions, including the Lower Mainland, Vancouver Island, and BC Interior
- final data weighted by gender and age within region based on the general BC population using Statistics Canada data
- a margin of error of ± 5.2% at an estimated 30% recall rate

Research conducted to track the effectiveness of our EEC Education and Outreach efforts would also include telephone interviews with homeowners (gas and non-gas) throughout our service area. Depending upon the sample sizes selected, the expected margin of error for the data collected would be approximately ± 5 to 7%, 19 times out of 20.

Once commercials and other education and outreach work are released into the marketplace, the only way to gauge if the communications tools are effective is tracking research. The term "tracking research," refers to telephone interviews among a representative sample of target-audience consumers. These interviews can be ***continuous*** (i.e., a certain number of interviews are conducted everyday or every week throughout the year) or ***pulsed*** (i.e., the interviewing is conducted in "waves," at discrete points in times, say every three months or every six months).

Tracking research can investigate the effectiveness of specific commercials or campaigns in terms of the recall of specific messages, changes in people's perceptions, and behavioural changes in the target audience. It answers questions like the following:

- What messages and ideas from the advertising do consumers remember?
- Do the remembered messages correspond to the advertising messages that the advertising was intended to communicate?

Advertising message recall is measured by an open-ended question, to which respondents give unaided, spontaneous answers. This question helps determine if the intended messages are getting through to consumers. Advertising message recall also provides an indication of consumer memory distortion and learning effects over time. That is, once a commercial starts running, consumers do not remember everything in it equally. Some elements stick in the memories of consumers, and other elements fade away. Knowing the elements that have the highest memory value is of great benefit in improving future creative executions.

Vendor Selection

To ensure that tracking data is comparable from time period to time period, it's important to stay with one research company and maintain constant methods. Although a request for proposal may be considered, it is very likely that the Companies will continue to employ TNS Global Research to conduct our EEC-related research activities. Staying with a single vendor has the following benefits:

- It facilitates possible synergies with other Terasen Gas advertising research requirements (i.e., Customer Choice, Safety).
- Ensures comparable tracking data over time. Just like our Customer Satisfaction research, the real value of ad tracking research comes from year over year review. Successive research provides insights into message refinement, creative development, and the long-term effect of our advertising.

Changing research vendors makes multi-year review impossible. Even small differences in methods like interviewing training, call-back policies, and editing and coding conventions will impede data comparability, and degrade overall research usefulness.

47.2 The Application also states that in the case of Trade Relations, targeted trades groups would be surveyed annually so as to monitor the effectiveness of the Companies' outreach and training efforts with these trades groups.

47.2.1 How much, by year and by utility, is the budgeted cost of the annual surveys? Does the budgeted cost assume that Terasen will be undertaking these surveys on its own?

Response:

A budgeted cost specifically for conducting surveys has not yet been developed by the Companies, as the full roster of trade relations activities has not yet been developed, and survey costs would be dependent on the type and number of trade relations activities conducted, as well as the type and number of trade relations groups that are targeted.

47.2.2 If Terasen is proposing that it would do these surveys on its own, why does it make sense for Terasen to do so, rather than to partner with other utilities and the Government to ensure a consistent message?

Response:

The Terasen Utilities are proposing in the Application that the surveys would be conducted with trade groups in order for the Companies to determine the effectiveness of the Companies' own activities with trade groups. The Companies would consider partnering so that trade groups would not become confused about what education and outreach efforts they are being surveyed about.

48.0 Reference: Exhibit B-1, Section 6.13, RIM, p. 85

48.1 Please express the RIM as a net present value dollar amount and for F2008 please provide the Companies' revenue requirement separated into commodity and "pipes" components.

Response:

The following table is the final (January 14, 2008) approved, by the BCUC, forecast 2008 revenue requirement in thousands of dollars for TGI.

"Pipes" – Gross Margin	$ 490,985
Commodity – Cost of Gas	1,021,804
Total Revenue Requirement	$1,512,789

The following table has the net present value amounts to derive the RIM measure for the Companies.

Revenue Impact over the life of the savings measures

2008-2010 (NPV 2007)	Free Rider Factor	
(Thousands of Dollars)	Included *	Excluded
Natural Gas Benefits	$76,705	$90,339
Costs		
Program	$34,530	$34,530
Communication	$21,835	$21,835
Revenue Loss	$101,240	$101,240
Total Costs	$157,605	$157,605
Revenue Impact	-$80,900	-$67,266

* Presented in Exhibit B-1, page 85, Table 6.13

49.0 Reference: Exhibit B-1, Section 6.13, Portfolio Approach and Alignment of Cost/Benefit Analysis, p. 85-86 and Appendix 4

Table 6.13 presents the Cost-Benefit Results for the EEC Portfolio including a Free Rider Factor. However, the Companies propose that the requirement to net out energy savings resulting from the participation of free riders be eliminated form the cost/benefit analyses for EEC programs in British Columbia.

49.1 Was Appendix 4 - 'DSM Activity at Other Utilities' prepared for TGI and/or TGVI? If not, who was it prepared for?

Response:

"DSM Activity at Other Utilities" report was prepared for TGI and TGVI. This report was prepared specifically for the EEC Application and to help the Terasen Utilities understand what others are doing so that the Companies can design and implement successful EEC programs for customers.

49.2 Who was (were) the author(s) of Appendix 4 and when was it prepared?

Response:

Michelle Petrusevich, Energy Efficiency Program Coordinator was the primary author of the report and Walter Wright, Market Research Analyst was the secondary author of the report. Background research was collected via the internet from utility websites, public websites, utility commission and government websites. Initial findings were followed up by personal telephone interviews with key DSM personnel at these utilities. The first phase of research was carried out between May and July 2007, while the second phase of research took place from November to December 2007.

49.3 Based on the information gained in preparing Appendix 4 and any other information available to the Companies, how are free–riders treated in the cost/benefit analyses of other jurisdictions?

Response:

Please refer to the response to BCUC IR 1.3.1.

49.4 On page 86 the Application states that the Companies are of the view that the inclusion of the effects of free riders in the cost-benefit test for EEC programs distorts the value of EEC programs and is counter to the objectives of the energy plan. Please explain why the Companies hold this view.

<u>Response:</u>

Please refer to the response to BCUC IR 1.3.1.

50.0 Reference: Exhibit B-1, Section 6.13, Free Riders, p. 86

50.1 The Companies state: "Including, the notional effects of free riders in the cost-benefit tests serves to reduce the number of programs that can be offered and consequently reduces the overall energy savings that customers will be able to realize through EEC programs."

Why does excluding free riders reduce the savings that customers would experience, when the excluded free riders, by definition, would have obtained the savings in any event?

<u>Response:</u>

The quoted passage was worded awkwardly. The point being made was a conceptual one: since including the free rider factor in the portfolio-level analysis results in the overall TRC being lower than if the free rider factor is excluded (as can be seen by comparing Tables 6.13 and 6.13a on pages 85 and 86 of the Application), it could conceivably limit the number of programs available in a portfolio from which customers could realize a benefit. In the case of the proposed portfolio, this is not a significant concern. . The difference between including free riders and excluding free riders is small (including free riders changes the TRC ratio from 3.1% to 2.9%, a change of 0.2%) and the overall portfolio level TRC for the proposed portfolio of EEC activity is still well above 1.0, the proposed TRC threshold.

51.0 Reference: Exhibit B-1, Section 6.13, Portfolio Approach and Alignment of Cost/Benefit Analysis, p. 87

The Application proposes that once a proposed regulation and implementation date for minimum efficiency standards for an appliance or building or energy system is announced by a regulating body, the Companies be permitted to attribute savings to market transformation programs for that particular appliance, building or energy system in its cost/benefit analyses at that time. Table 6.13b proposes specific attribution rates for the first five regulation years.

51.1 Please provide all studies that form the basis for the attribution rates that underlie the attribution rates in Table 6.13b.

Response:

The Terasen Utilities have developed the specific attribution rates proposed in this Application based on judgment as to a fair and reasonable attribution rate. Attribution of savings from codes and standards is a relatively new phenomenon, and no consistent practice has yet been developed. In Ontario, the utilities do not have a set scale for attribution, but they do take centrality (i.e. who started and administered the program) and attribution (including partnering for program delivery or new regulations) into consideration. There is no set scale, but rather it is done on a one-off basis depending on the program. More information can be found in the OEB's DSM Handbook, filed in response to BCUC IR 1.84.1.

In California, the investor-owned utilities receive credit for energy savings resulting from the IOU's contribution to or intervention in increased stringency in an energy code cycle. Title 24, the California building energy code, gets updated every three years. Currently, California is operating under 2005 Title 24. California IOUs will get credit, for example, for the increase in the stringency of the Title 24 standard from 2001 to 2005, based on verified energy savings. There is a model used to attribute energy savings that has been developed by a consultant, HMG (Heschong Mahone Group). The HMG Report, "Codes and Standards Program Savings Estimate" describes the model. (www.calmac.org/publications/CandS_Savings_Estimate_Report_-_Posted_V3.pdf)

There is another report prepared for Southern California Edison by Quantec, "The Statewide Codes and Standards Market Adoption and Non-Compliance Rates". It is available at www.calmac.org/publications/Codes_and_Standards_Final_Report.pdf.

The Companies believe that the proposed attribution rates are reasonable. The partial and declining attribution of energy savings resulting from the introduction of regulation of minimum efficiency levels, or codes and standards, at 50% in the first year and declining by 10% for four years thereafter recognizes that there are other market actors contributing to the introduction of regulations or codes and standards.

51.2 Is Terasen proposing those attribution rates regardless of the type of program or Terasen's level of support for the market transformation?

Response:

No - the attribution rate should reflect the level of the Companies' support for market transformation. In cases where market transformation has been a multi-party effort, attribution rates would be negotiated with other parties, dependent on their relative contribution to market transformation.

51.3 Should the attribution rate reflect the type of program or Terasen's level of support for the market transformation? If not, why not? If other organizations, such as BC Hydro and provincial, federal or local governments also provided incentives or consumer information, how would the Companies propose to modify the attribution rates?

Response:

Please refer to the response to BCUC IR 1.51.2.

52.0 Reference: Exhibit B-1, 7.1.2. Revenue Requirements and Rate Impacts, pp. 92-98, Table 7.1.2.2 and Table 4.1.2.2 – EEC Expenditure

52.1 On page 95 it shows Table 7.1.2.2 TGI - Impacts of Total EEC Expenditure on Annual Revenue Requirements.

52.1.1 Please extend the table and include all amortization years, segment the earned return between interest and return on equity, and at the end of the columns include a sum total of the rows where appropriate. Provide the working spreadsheet for this table.

Response:

The following table is an extension of Table 7.1.2.2 (Page 95 of the Application) from 2020 to 2030 plus a summation of the Cost of Service line items. The table has been updated for changes in the forecast income tax rates from 2011 forward.

TERASEN GAS INC. (3 Divisions)
DEMAND SIDE MANAGEMENT
$000's

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
1	**Current DSM**																								
2	Beginning of Year Balance	$ 1,526	$ 754	$ 370	$ 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Tax Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Amortization	(772)	(384)	(353)	(17)																				
7	End of Year Balance	754	370	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
8																									
9	**New EEC**																								
10	Beginning of Year Balance	-	8,537	17,999	29,287	27,756	26,224	24,692	23,160	21,628	20,097	18,565	17,033	15,501	13,970	12,438	10,906	9,374	7,842	6,311	4,779	3,247	1,715	610	
11	Additions	12,372	14,128	17,196	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
12	Tax Adjustment	(3,835)	(4,238)	(4,987)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
13	Net Additions	8,537	9,890	12,209	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	Amortization	-	(427)	(921)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,105)	(610)	
15	End of Year Balance	8,537	17,999	29,287	27,756	26,224	24,692	23,160	21,628	20,097	18,565	17,033	15,501	13,970	12,438	10,906	9,374	7,842	6,311	4,779	3,247	1,715	610	(0)	
16																									
17	**Total Deferred DSM**																								
18	Beginning of Year Balance	1,526	9,291	18,369	29,304	27,756	26,224	24,692	23,160	21,628	20,097	18,565	17,033	15,501	13,970	12,438	10,906	9,374	7,842	6,311	4,779	3,247	1,715	610	
19	Additions	12,372	14,128	17,196	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	Tax Adjustment	(3,835)	(4,238)	(4,987)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	Net Additions	8,537	9,890	12,209	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
22	Amortization	(772)	(811)	(1,274)	(1,549)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,105)	(610)	
23	End of Year Balance	9,291	18,369	29,304	27,756	26,224	24,692	23,160	21,628	20,097	18,565	17,033	15,501	13,970	12,438	10,906	9,374	7,842	6,311	4,779	3,247	1,715	610	(0)	
26																									
27	**Cost of Service**																								
28	Operating & Maintenance Expense	$ 1,624	$ 1,624	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,248
29	Amortization Expense	772	811	1,274	1,549	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,105	610	32,161
30	Income Tax Expense	420	526	814	914	824	808	792	776	759	743	727	711	694	678	662	646	629	613	597	581	565	401	218	15,099
31																									
32	Earned Return - Debt	241	617	1,063	1,272	1,204	1,135	1,067	999	930	862	794	725	657	589	521	452	384	316	247	179	111	52	14	14,430
33	Earned Return - Equity	163	417	719	861	815	768	722	676	630	583	537	491	445	398	352	306	260	214	167	121	75	35	9	9,765
34	Earned Return	404	1,034	1,782	2,133	2,018	1,904	1,789	1,675	1,560	1,445	1,331	1,216	1,102	987	873	758	644	529	415	300	186	87	23	24,195
35	Total Cost of Service	$ 3,221	$ 3,995	$ 3,871	$ 4,596	$ 4,374	$ 4,244	$ 4,113	$ 3,982	$ 3,851	$ 3,720	$ 3,590	$ 3,459	$ 3,328	$ 3,197	$ 3,066	$ 2,936	$ 2,805	$ 2,674	$ 2,543	$ 2,413	$ 2,282	$ 1,592	$ 851	$ 74,703
36	Volume (TJ/year)	139,909	141,993	143,432	145,157	146,805	148,459	150,068	151,673	153,211	154,644	155,987	157,296	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	158,554	3,532,725
37	Cost $/GJ	$0.0230	$0.0281	$0.0270	$0.0317	$0.0298	$0.0286	$0.0274	$0.0263	$0.0251	$0.0241	$0.0230	$0.0220	$0.0210	$0.0202	$0.0193	$0.0185	$0.0177	$0.0169	$0.0160	$0.0152	$0.0144	$0.0100	$0.0054	$0.0211

52.2 On page 97 it shows Table 7.1.2.3 TGVI – Impacts of Total EEC Expenditure on Revenue Requirements.

52.2.1 Please extend the table and include all amortization years, segment the earned return between interest and return on equity, and at the end of the columns include a sum total of the rows where appropriate. Provide the working spreadsheet for this table.

Response:

The following table is an extension of Table 7.1.2.3 (Page 97 of the Application) from 2020 to 2030 plus a summation of the Cost of Service line items. This table has been updated to apply the TGVI capital structure and embedded financing costs from the 2007 Settlement Update for the forecast year 2008. Also, the table was updated for changes in the forecast income tax rates from 2011 forward.

TERASEN GAS (VANCOUVER ISLAND) INC.
DEMAND SIDE MANAGEMENT
$000's

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
1	**Current DSM**																								
2	Beginning of Year Balance	$ 195	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Tax Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Amortization	(195)																							
7	End of Year Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
8																									
9	**New EEC**																								
10	Beginning of Year Balance	-	1,608	3,307	5,831	5,527	5,223	4,919	4,615	4,311	4,007	3,703	3,399	3,095	2,791	2,487	2,183	1,879	1,574	1,270	966	662	358	135	
11	Additions	2,330	2,543	3,793	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
12	Tax Adjustment	(722)	(763)	(1,100)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
13	Net Additions	1,608	1,780	2,693	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	Amortization	-	(80)	(169)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(224)	(135)	
15	End of Year Balance	1,608	3,307	5,831	5,527	5,223	4,919	4,615	4,311	4,007	3,703	3,399	3,095	2,791	2,487	2,183	1,879	1,574	1,270	966	662	358	135	(0)	
16																									
17	**Total Deferred DSM**																								
18	Beginning of Year Balance	195	1,608	3,307	5,831	5,527	5,223	4,919	4,615	4,311	4,007	3,703	3,399	3,095	2,791	2,487	2,183	1,879	1,574	1,270	966	662	358	135	
19	Additions	2,330	2,543	3,793	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	Tax Adjustment	(722)	(763)	(1,100)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	Net Additions	1,608	1,780	2,693	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
22	Amortization	(195)	(80)	(169)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(224)	(135)	
23	End of Year Balance	1,608	3,307	5,831	5,527	5,223	4,919	4,615	4,311	4,007	3,703	3,399	3,095	2,791	2,487	2,183	1,879	1,574	1,270	966	662	358	135	(0)	
24																									
27	Cost of Service																								
28	Operating & Maintenance Expense	$ 500	$ 500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,000
29	Amortization Expense	195	80	169	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	224	135	6,276
30	Income Tax Expense	103	74	139	196	177	173	169	165	161	157	153	149	145	141	137	133	129	125	121	117	114	82	48	3,112
31																									
32	Earned Return - Debt	31	84	157	195	184	174	163	153	143	132	122	111	101	90	80	70	59	49	38	28	17	8	2	2,193
33	Earned Return - Equity	34	92	170	212	200	189	178	166	155	144	132	121	110	98	87	76	64	53	42	30	19	9	3	2,384
34	Total Earned Return	65	176	327	406	385	363	341	319	298	276	254	232	211	189	167	145	124	102	80	58	37	18	5	4,577
35	Total Cost of Service	$ 862	$ 830	$ 635	$ 906	$ 866	$ 840	$ 814	$ 789	$ 763	$ 737	$ 711	$ 686	$ 660	$ 634	$ 609	$ 583	$ 557	$ 531	$ 506	$ 480	$ 454	$ 323	$ 188	$ 14,964
36	Volume (TJ/year)	12,282	12,649	13,018	13,415	13,873	14,254	14,590	14,925	15,246	15,543	15,809	16,053	16,280	16,280	16,280	16,280	16,280	16,280	16,280	16,280	16,280	16,280	16,280	350,738
37	Cost $/GJ	$0.0702	$0.0656	$0.0488	$0.0675	$0.0624	$0.0589	$0.0558	$0.0528	$0.0500	$0.0474	$0.0450	$0.0427	$0.0405	$0.0390	$0.0374	$0.0358	$0.0342	$0.0326	$0.0311	$0.0295	$0.0279	$0.0198	$0.0115	$0.0427

52.3 Please modify Table 7.1.2.2 assuming the proposed incremental TGI Expenditures in 2008, 2009 and 2010 are expensed for non-incentive costs and amortized over three years for incentive costs (i.e., the current methodology).

Response:

The following table is based on modifying the results in the response to BCUC IR 1.52.1. The non-incentive costs for 2008 – 2010 for TGI can be found on Table 6.2a on Page 54 of the Application under the heading "Program Costs" for each of the three years. If the Commission was to order TGI to recover the costs under this "current methodology" TGI would want the increased O&M costs in excess of the PBR costs of $1.624 million dollars to be regarded as an exogenous amount and to be included in a deferral account for 2008 costs and added to the O&M costs for setting rates in 2009. The 'current methodology' results in an average increased cost of service of approximately 6 ¢ per gigajoule whereas the average increase in cost of service in response to 1.52.1 is 3 ¢ per gigajoule in the initial years.

TERASEN GAS INC. (3 Divisions)
DEMAND SIDE MANAGEMENT
$000's

Line No.	Particulars	2008	2009	2010	2011	2012	2013	Total
1	**Current DSM**							
2	Beginning of Year Balance	$ 1,526	$ 754	$ 370	$ 17	$ -	$ -	
3	Additions	-	-	-	-	-	-	
4	Tax Adjustment	-	-	-	-	-	-	
5	Net Additions	-	-	-	-	-	-	
6	Amortization	(772)	(384)	(353)	(17)			
7	End of Year Balance	754	370	17	-	-	-	
8								
9	**New EEC**							
10	Beginning of Year Balance	-	4,669	9,174	12,444	6,585	2,282	
11	Additions	6,766	8,660	9,643	-	-	-	
12	Tax Adjustment	(2,097)	(2,598)	(2,796)	-	-	-	
13	Net Additions	4,669	6,062	6,847	-	-	-	
14	Amortization	-	(1,556)	(3,577)	(5,859)	(4,303)	(2,282)	
15	End of Year Balance	4,669	9,174	12,444	6,585	2,282	-	
16								
17	**Total Deferred DSM**							
18	Beginning of Year Balance	1,526	5,423	9,544	12,461	6,585	2,282	
19	Additions	6,766	8,660	9,643	-	-	-	
20	Tax Adjustment	(2,097)	(2,598)	(2,796)	-	-	-	
21	Net Additions	4,669	6,062	6,847	-	-	-	
22	Amortization	(772)	(1,940)	(3,930)	(5,876)	(4,303)	(2,282)	
23	End of Year Balance	5,423	9,544	12,461	6,585	2,282	-	
24								
27	**Cost of Service**							
28	Operating & Maintenance Expense	$ 7,230	$ 7,092	$ 7,553	$ -	$ -	$ -	$ 21,875
29	Amortization Expense	772	1,940	3,930	5,876	4,303	2,282	19,103
30	Income Tax Expense	394	928	1,741	2,338	1,559	814	7,774
31								
32	Earned Return - Debt	155	334	491	425	198	51	1,653
33	Earned Return - Equity	105	226	332	287	134	34	1,118
34	Earned Return	260	560	823	712	332	85	2,771
35	Total Cost of Service	$ 8,656	$ 10,520	$ 14,046	$ 8,926	$ 6,193	$ 3,181	$ 51,523
36	Volume (TJ/year)	139,909	141,993	143,432	145,157	146,805	148,459	865,755
37	Cost $/GJ	$0.0619	$0.0741	$0.0979	$0.0615	$0.0422	$0.0214	$0.0595

52.4 Assuming that TGI continues EEC programs into the future, when does TGI expect the proposed DSM regulatory deferral account balance to reach a steady state so that it does not continue to grow? What is the estimated steady state balance?

Response:

At this time it is not known what the EEC costs would be beyond 2010. Extrapolating out into the future beyond 2015 would be speculative. However, to respond to this question, TGI has assumed a constant spend of $17,196,000 (2010 forecast amount) from 2011 onwards. Under these assumptions the deferral account would reach a steady state in 2031 at $133,613,000.

TERASEN GAS INC. (3 Divisions)
DEMAND SIDE MANAGEMENT
$000's

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	**Current DSM**																									
2	Beginning of Year Balance	$ 1,526	$ 754	$ 370	$ 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Amortization	(772)	(384)	(353)	(17)																					
7	End of Year Balance	754	370	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8																										
9	**New EEC**																									
10	Beginning of Year Balance	-	8,537	17,999	29,287	40,223	50,793	60,726	70,024	78,685	86,710	94,098	100,851	106,967	112,447	117,290	121,498	125,069	128,004	130,302	131,965	132,991	133,381	133,561	133,600	133,613
11	Additions	12,372	14,128	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196
12	Tax Adjustment	(3,835)	(4,238)	(4,987)	(4,729)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)
13	Net Additions	8,537	9,890	12,209	12,467	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725
14	Amortization	-	(427)	(921)	(1,532)	(2,155)	(2,791)	(3,428)	(4,064)	(4,700)	(5,336)	(5,973)	(6,609)	(7,245)	(7,881)	(8,518)	(9,154)	(9,790)	(10,426)	(11,063)	(11,699)	(12,335)	(12,545)	(12,686)	(12,712)	(12,725)
15	End of Year Balance	8,537	17,999	29,287	40,223	50,793	60,726	70,024	78,685	86,710	94,098	100,851	106,967	112,447	117,290	121,498	125,069	128,004	130,302	131,965	132,991	133,381	133,561	133,600	133,613	133,613
16																										
17	**Total Deferred DSM**																									
18	Beginning of Year Balance	1,526	9,291	18,369	29,304	40,223	50,793	60,726	70,024	78,685	86,710	94,098	100,851	106,967	112,447	117,290	121,498	125,069	128,004	130,302	131,965	132,991	133,381	133,561	133,600	133,613
19	Additions	12,372	14,128	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196	17,196
20	Tax Adjustment	(3,835)	(4,238)	(4,987)	(4,729)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)	(4,471)
21	Net Additions	8,537	9,890	12,209	12,467	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725	12,725
22	Amortization	(772)	(811)	(1,274)	(1,549)	(2,155)	(2,791)	(3,428)	(4,064)	(4,700)	(5,336)	(5,973)	(6,609)	(7,245)	(7,881)	(8,518)	(9,154)	(9,790)	(10,426)	(11,063)	(11,699)	(12,335)	(12,545)	(12,686)	(12,712)	(12,725)
23	End of Year Balance	9,291	18,369	29,304	40,223	50,793	60,726	70,024	78,685	86,710	94,098	100,851	106,967	112,447	117,290	121,498	125,069	128,004	130,302	131,965	132,991	133,381	133,561	133,600	133,613	133,613

53.0 Reference: Exhibit B-1, Section 7.2, Greenhouse Gas Emission Reductions, p. 99

The Application uses CO2e factors of 0.05069 tonnes/GJ for natural gas and 550 tonnes/GWh for electricity.

53.1 What is the source of the CO2e factor for natural gas?

Response:

Source was originally from Environment Canada 1990-1995 Trends in Greenhouse Gases Sources & Sinks report, used as an emissions factor for buildings. While Environment Canada no longer provides this report on its website, the emission factor used is considered reasonable. As an example, the Province of British Columbia uses an emission factor of 0.04966 in calculating the BC carbon tax.

53.2 Please provide the page from the BC Hydro CPR referenced in footnote 32.

Response:

Included in Attachment 53.2.

53.3 In Terasen's view, will the provincial Cap and Trade program capture GHG emissions embedded in the electricity distributed by BC Hydro? Why or why not?

Response:

The Terasen Utilities are unsure at this time as to whether or not the electricity distributed by BC Hydro will be included in the provincial Cap and Trade program. The regulations as to what is included in the provincial Cap and Trade program are yet to be defined by the province. Also, how this provincial program will work with the Western Climate Initiative (WCI) Cap and Trade program is not yet fully understood.

54.0 Reference: Exhibit B-1, Section 7.2, GHG Emissions, pp. 99, 100

54.1 Please provide in fully functioning electronic form, the spreadsheet underlying Tables 7.2 and 7.2a and all linked or related spreadsheets.

Response:

Attachment 54.1 contains the fully functioning electronic spreadsheet.

55.0 Reference: Exhibit B-1, Section 7.3.2, Policy Action #2, pp. 101-102

55.1 The Companies state on page 101 that they have enjoyed partnerships delivering incentive, education and training energy efficiency programs with BC Hydro and FortisBC, the Province, the federal government, manufacturers, industry associations, non-profit organizations and local governments.

To what extent has Terasen discussed or proposed joint action with BC Hydro or FortisBC to coordinate fuel switching activities? What was the response to any such discussions or proposals?

Response:

TGI does not currently have funding available for fuel switching activities, so there have been no discussions with BC Hydro and Fortis BC about coordinating fuel switching activities for TGI. Programs for TGVI were suspended pending the submission of this Application, as noted in the response to BCUC IR 1.12.1, so there have been no recent discussions with BC Hydro about coordinating fuel switching activities for TGVI. Please note that BC Hydro contributed to the Yank the Tank program for TGVI customers, as well as the Think Grand program. Yank the Tank was a program designed to encourage TGVI customers to install a natural gas water heater, while Think Grand was a program designed to encourage Vancouver Island builders to install natural gas fired Energy Star space heating systems and natural gas water heaters.

55.2 The Application states on page 101 that more funding for the initiatives outlined and requested with the Application would allow the Companies to expand its incentive and education program efforts, in partnership with other entities offering effective joint programs.

Would it not be preferable for Terasen to explore joint programs with potential partners and to bring forward an application for approval of the Terasen portion of defined joint programs? Please comment.

Response:

As noted on page 50 of the Application, it is the view of the Companies that it is most efficient for the Commission to approve the overall expenditure level, by utility, for the Funding Period, rather than approving the funding by program area, or by individual program initiative, in order to respond quickly to opportunities that might arise, and in order to reduce the administrative burden to the Companies, helping to increase value to customers.

55.3 The Application states on page 102 that without additional funding the Terasen Utilities would not be in a position to implement coordinated programs that are incremental to current levels of DSM activity.

Has Terasen identified any specific coordinated programs with specific partners? If so please describe the programs and the partnership arrangements.

Response:

At the time of writing, the Companies are in discussion with BC Hydro and Fortis BC about the electric utilities contributing a financial incentive to Energy Star Heating Upgrade program participants that choose to purchase an Energy Star furnace with a variable speed motor. These discussions are not concluded so the Companies are unable to describe the specific partnership arrangements. The Companies have not identified any specific coordinated programs.

56.0 Reference: Exhibit B-1, Section 7.3.3, Cost Effectiveness, p. 102

56.1 It is stated that this Application represents a funding request for all cost-effective measures in the Habart Report. Please define "cost-effective" in terms of all of the proposed DSM tests.

<u>Response:</u>

Cost-effectiveness was based on the TRC results. The Companies are awaiting MEMPR's proposed regulations on cost-effectiveness testing for DSM programs.

56.2 Please list all of the cost effective measures in the Habart Report for which funding is requested and for each measure provide the values of the DSM tests, measure costs, incentives, administration cost, savings in GJ and dollars per unit, electricity savings in kW.h and dollars, number of customers participating, penetration rates and lost revenue, in a format that totals the requested funding.

<u>Response:</u>

Workbooks are attached. Please note that the workbooks represent the measures from the Habart rescreening that then underwent further initial program development work described in the responses to BCUC IR 1.73.1, 74.1 and 75.1. The expenditures requested are based upon the workbooks attached.

Included in Attachment 56.2 are two sets of workbooks representing two scenarios: free riders included and free riders excluded. There is one workbook for each of TGI Residential, TGVI Residential, TGI Commercial and TGVI Commercial. Please refer to the table of contents at the beginning of each workbook for an explanation as to how the workbooks are laid out.

Market size is provided for TGI Residential New Construction and Retrofit, and for TGVI Residential New Construction. The New Construction market size estimates are based upon CMHC data, and the TGI Retrofit market size estimates are based upon the 2003 TGI Residential End Use Study. Terasen Gas did not have End Use and other studies available to assist in determining the market size for the Commercial sector for TGI and TGVI, or the Residential Retrofit sector for TGVI. Instead, Terasen relied on the internal experience of the Companies' Account Managers and Technical Sales and Support group to develop estimates of participation.

It should be noted that one of the residential programs combines more than one measure. "EE E* Hot Water Saving Appliances" translates to Energy Efficiency Energy Star Hot Water Saving Appliances, and it includes Energy Star Dishwashers and Energy Star Clothes washers.

57.0 Reference: Exhibit B-1, Section 7.3.3, Policy Action #3, p. 104

57.1 Please provide a table for TGI and TGVI showing the number of accounts and the volume by rates class. Please indicate which rate classes are considered to be residential, commercial and industrial categories. Please confirm that the Other category in figure 7.3a includes is made up of commercial and industrial accounts.

Response:

The number of accounts and volumes were included in the application as tables 3.1 and 3.1a (pages 20 and 21 respectively). Following are those figures:

TGVI			
Rate Schedule	**Category**	**Customers**	**Annual Consumption (TJ)**
RGS	Residential	85,030	4,806
SCS1	Commercial	4,153	275
SCS2	Commercial	1,855	540
LCS1	Commercial	1,539	1,378
LCS2	Commercial	573	1,329
AGS	Commercial	827	1,138
LCS3	Commercial	132	2,370
HLF	Commercial	7	273
ILF	Commercial	8	158
Total		**94,124**	**12,267**

TGI			
Rate Schedule	**Category**	**Customers**	**Annual Consumption (TJ)**
1	Residential	757,261	75,393
2	Commercial	75,020	22,675
3	Commercial	4,695	16,214
5	Commercial	398	4,206
7	Industrial	4	54
22	Industrial	55	35,843
23	Commercial	1,185	5,212
25	Commercial	576	16,095
27	Industrial	98	6,296
Total		**839,292**	**181,988**

The Other category in figure 7.3a is confirmed to include both commercial and industrial accounts. For the purposes of this application, Rate Schedules 5 and 25 are classified as Commercial customers eligible for participation in the Commercial Energy Efficiency Program Area, though they are typically classified as an Industrial Rate Schedule in other TGI applications.

57.2 Please provide a table or tables showing for the last 10 years, the use per account for residential and commercial customers for each of TGI and TGVI, and the average burner tip rate for gas for each of those customer groups.

Response:

TGI Lower Mainland Rate Schedule 1		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
1998	123	$5.581
1999	122	$6.328
2000	117	$8.404
2001	105	$11.910
2002	113	$10.284
2003	112	$11.714
2004	110	$11.470
2005	104	$12.456
2006	103	$12.745
2007	103	$12.391

TGI Inland Rate Schedule 1		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
1998	102	$5.554
1999	104	$6.300
2000	99	$8.377
2001	88	$11.891
2002	88	$10.480
2003	89	$11.896
2004	86	$11.694
2005	82	$12.678
2006	82	$13.031
2007	80	$12.737

TGI Columbia Rate Schedule 1		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
1998	110	$5.522
1999	113	$6.263
2000	108	$8.361
2001	96	$11.936
2002	96	$10.470
2003	96	$11.878
2004	91	$11.750
2005	89	$12.685
2006	87	$13.018
2007	87	$12.676

TGI Lower Mainland Rate Schedule 2		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
1998	345	$5.229
1999	347	$5.900
2000	327	$7.976
2001	309	$11.359
2002	315	$9.757
2003	330	$11.089
2004	323	$10.783
2005	314	$11.771
2006	325	$11.914
2007	327	$11.598

TGI Lower Mainland Rate Schedule 3		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
1998	3,992	$4.274
1999	3,952	$4.920
2000	3,616	$6.922
2001	3,318	$10.270
2002	3,379	$8.695
2003	3,371	$10.053
2004	3,485	$9.784
2005	3,365	$13.841
2006	3,267	$11.185
2007	3,405	$10.749

TGVI Residential General Service		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
2003	62	$14.385
2004	59	$14.706
2005	59	$15.367
2006	60	$15.323
2007	57	$15.925

**Use Rate Data prior to 2003 not available for current rate classes, different rate classes were in place from 1997-2002, prior to the 2002 Centra Gas Rate Design Application*

TGVI Small Commercial Service 1		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
2003	71	$15.330
2004	68	$15.622
2005	75	$16.126
2006	75	$16.913
2007	91	$17.434

**Use Rate Data prior to 2003 not available for current rate classes, different rate classes were in place from 1997-2002, prior to the 2002 Centra Gas Rate Design Application*

TGVI Small Commercial Service 2		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
2003	306	$13.603
2004	294	$13.882
2005	314	$14.475
2006	314	$15.241
2007	310	$16.022

**Use Rate Data prior to 2003 not available for current rate classes, different rate classes were in place from 1997-2002, prior to the 2002 Centra Gas Rate Design Application*

TGVI Large Commercial Service 1		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
2003	917	$10.546
2004	901	$9.961
2005	943	$10.615
2006	903	$11.655
2007	943	$12.794

**Use Rate Data prior to 2003 not available for current rate classes, different rate classes were in place from 1997-2002, prior to the 2002 Centra Gas Rate Design Application*

TGVI Large Commercial Service 2		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
2003	2,348	$9.908
2004	2,344	$9.432
2005	2,384	$10.123
2006	2,295	$11.070
2007	2,406	$11.603

**Use Rate Data prior to 2003 not available for current rate classes, different rate classes were in place from 1997-2002, prior to the 2002 Centra Gas Rate Design Application*

TGVI Large Commercial Service 3		
Year	**Use per Customer (GJs)**	**Weighted Average Burner-tip Rate per GJ (based on Use per Customer)**
2003	16,481	$9.311
2004	16,850	$8.868
2005	16,521	$9.575
2006	17,379	$10.490
2007	17,694	$11.024

**Use Rate Data prior to 2003 not available for current rate classes, different rate classes were in place from 1997-2002, prior to the 2002 Centra Gas Rate Design Application*

58.0 Reference: Exhibit B-1, Section 7.3.3, DSM Affordable Housing Working Group, pp. 104, 105

58.1 The Companies state that MEMPR had requested they lead the establishment of the above noted working group, and that continuation of this leadership is dependent on approval for increased EEC expenditure. If the Commission were to approve only increased expenditure related to this working group, what amount would the Companies require?

Response:

The Companies' participation in and leadership of this group are in anticipation of having funding for incentives for a DSM for Affordable Housing program under the "Joint Initiatives" program area. ("DSM for Affordable Housing" is alternatively called "Energy Efficiency for Low Income Homes"). The group's work is intended to coordinate incentive and information program offerings specifically targeted to the Affordable Housing Sector. The expenditure proposed for Joint Initiatives, of which DSM for Affordable Housing is one, is a placeholder amount; work needs to be done on program development similar to the work that was done to develop the activities and amounts proposed for the Energy Efficiency, Fuel Switching and Communications and Outreach areas. However, in order to start program development in the Joint Initiatives program area, including the DSM for Affordable Housing area, the Companies need to know directionally what level is appropriate for program expenditures. The Companies relied on their best judgment to develop this placeholder expenditure amount for Joint Initiatives, including DSM for Affordable Housing. If an appropriate program cannot be developed for Joint Initiatives including DSM for Affordable Housing, the $1,000,000 per year proposed would be reallocated to another program area.

58.2 Please explain the rationale for treating this funding as capital rather than expense.

Response:

Please refer to the response to BCUC IR 1.39.1.

59.0 Reference: Exhibit B-1, Section 7.3.4, Policy Action #5, p. 106

The Companies state that they have identified specific areas of activity that would support Policy Action #5 and that the Companies could undertake with an increase in EEC funding, such as contributing to design costs for buildings operating at 60% below the Model National Energy Code for Buildings.

59.1 Please identify the specific areas of activity identified.

Response:

Please see sections 6.3.1 and 6.3.2 on pages 57 to 63 of the Application. All the activities detailed in these sections serve to increase the efficiency of new and existing buildings, whether it be the design of buildings of themselves, or the level of energy consumed by buildings as a result of the appliances and systems within them.

59.2 Please describe how a program of contributing to design costs for buildings operating at 60% below the Model National Energy Code would work?

Response:

The specific details of this program have not yet been developed so the Companies are unable to describe exactly how such a program would work. A program such as this would be designed in conjunction with industry stakeholders such as developers, architects, designers and engineers to ensure that it was effective.

60.0 Reference: Exhibit B-1, Section 7.3.6, Policy Action #6, p. 107

The Companies state that they will pursue co-funding a pilot energy performance labeling program for new and existing gas –heated homes if the Application is approved.

60.1 What is the specific amount of funding requested for co-funding a pilot energy performance labeling program?

Response:

A building labeling program is currently under development by MEMPR and BC Hydro, with involvement from the Terasen Utilities. It is at the initial stages, with the first step being to establish some normalized energy performance benchmarking. Until the program is more developed, the Companies are unable to establish a specific amount for co-funding a pilot energy performance labeling program.

This is in the Joint Initiatives program area, and it should be noted that the Companies are seeking high-level approval of the total amount to be expended not to exceed $56.6 million by 2010, rather than funding for specific initiatives such as a building labeling pilot.

60.2 If it is a co-funded project, why should it be restricted to gas-heated homes?

Response:

While such a program might be available to all homes, the Companies' financial contribution would be restricted to the proportion of gas-heated homes targeted under such a program.

61.0 Reference: Exhibit B-1, Section 7.3.7, Policy Action #9, p. 107

The Companies state that if the Application is approved, the Companies intend to contribute funding to the pool of monies to which communities apply under the Community Action on Energy Efficiency.

61.1 What is the specific amount of funding requested for the Companies contribution?

<u>Response:</u>

Please refer to the response to BCUC IR 1.31.3.

61.2 Is a contribution to the fund required by Policy Action #9, and is a contribution to the fund the most effective way for Terasen to support Energy Efficiency by local governments.

<u>Response:</u>

The Policy Action as written makes no specific mention of a requirement for a contribution to the fund by the Terasen Utilities. The Terasen Utilities have not, to date, conducted analysis or discussed with municipalities which would be the most effective way for the Companies to support Energy Efficiency by local governments. A contribution would be <u>one</u> way for the Terasen Utilities to support Energy Efficiency by local governments – there are others. Some of these would be:

- contributing to upgrades at municipal facilities
- participating in the implementation of communication programs aimed at residents of a municipality about the benefits of conservation and availability of incentives;
- participating in the establishment of efficient district energy systems

Without conducting some discussions with local governments, the Companies are not in a position to comment on what would be the most effective way for the Companies to support Energy Efficiency by local governments. However, the Companies would suspect that the response to the question, "What is the most effective way for the Terasen Utilities to support Energy Efficiency by local governments" would vary from municipality to municipality.

62.0 Reference: Exhibit B-1, Section 7.3.6, Policy Action #6, p. 110

62.1 On page 110, Terasen states that the funding for fuel switching that the Companies are proposing would help to address the disparity in capital costs between natural gas and electrical equipment, so as to encourage more customers to choose efficient natural gas appliances over their electrical equivalents which would also have the effect of lowering regional GHGs.

Does Terasen think that the funding for fuel switching will lower British Columbia's GHG's? Why or why not?

<u>Response:</u>

The majority of fuel switching activity the Companies are proposing in the Application is for TGVI. Fuel switching expenditures for TGVI are proposed to be a total of $2.367 million vs. $1.329 million for TGI. The breakdown of fuel switching activities proposed for TGI and TGVI can be found in Table 6.4 on page 63 of the Application.

It is the view of the Companies that GHG emissions are a regional, if not continental or even global issue and that GHG emissions must be viewed in that context. Looking at British Columbia in isolation does not provide an adequate view of the impacts from various activities including fuel switching, and could in fact, produce unintended consequences such as mass electrification. Mass electrification could happen if British Columbians take the view that ALL of the electricity <u>consumed</u> in the Province has no greenhouse gas consequence. Mass electrification runs contrary to the electricity conservation and electricity self-sufficiency goals of the 2007 BC Energy Plan.

As noted in the Application, the electrical grid in British Columbia is not an island; it is connected to Alberta and the western US. Fuel switching will reduce the amounts of electricity that BC Hydro needs to satisfy our domestic needs in British Columbia, and as a consequence makes electricity generated in British Columbia more available for export throughout the western interconnection. The marginal source of electricity in the western interconnection is either coal fired or gas fired, which produce significantly greater GHG emissions than direct use of natural gas in end use appliances. This is true today and will continue to be true in 2016 when BC Hydro is required to be self-sufficient in its supply requirements. Exports of electricity from BC now and in the future will offset the need to generate electricity by burning coal or natural gas at a much lower rate of efficiency.

It is expected that BC Hydro will continue to engage in trading activity to optimize the system, exporting power generated in British Columbia primarily through hydroelectricity when prices are high, and replacing that power by importing when prices are low. Both the imports that are currently needed to supply our domestic needs, and the imports that arise from trading activity, come from jurisdictions where electricity is generated through the combustion of natural gas and coal in generating facilities that have efficiency levels lower, and consequently higher GHG and other impacts, than natural gas end use appliances.

63.0 Reference: Exhibit B-1, Section 7.3.10, Policy Actions regarding Skills Training and Labour Policies, p. 111

63.1 The Application states that with increased EEC funding, the Companies would look to increase trade relations and trades training activity on efficient natural gas equipment and the optimal operation of energy efficient buildings.

Is Terasen the best vehicle for delivering trades training? How would Terasen propose to partner with others on the issue of trade relations and trades training, if at all?

Response:

Please see Section 6.7 on page 68 of the Application for more information on the Companies' proposed trade relations activities. The specific activities related to trades training have not yet been developed, however at a high level, the Companies would propose to partner with industry and trades groups to identify training gaps in the skills needed to deliver the Companies' portfolio of EEC activities, and would look to co-fund and actively participate in curriculum and collateral development for the required training. It is unlikely that the Companies would deliver trades training directly. The Companies would more likely rely on partnership with organizations and agencies that are engaged in directly delivering training.

64.0 Reference: Exhibit B-1, Appendix 1, CPR, Natural Conservation, p. E-ii

64.1 Please provide all future changes in the price of natural gas and electricity used in estimating natural conservation.

Response:

Marbek Resource Consultants estimated natural conservation based on assumptions around the modest continuation of appliance penetration trends. Unit Energy Consumption (UEC) data, based on NR Can's Survey of Household Energy Use were used for existing and new appliance stock. A discussion of "Natural' Changes to Appliance and Heating Energy Use" can be found in Section 3.5 of the CPR, on pages 38 – 41 of the Residential Section of Appendix 1. The assumed prices for natural gas and electricity in the Marbek CPR study can be found in Section 4.2.1 of the CPR, on pages 45 and 46 of the Residential Section of Appendix 1.

65.0 Reference: Exhibit B-1, Appendix 1, CPR, DSM Incentive, p. E-xii

65.1 Please confirm that no DSM incentive will be applicable to the programs which may result from this application.

Response:

The EEC Application does not request a DSM incentive for the proposed Energy Efficiency and Conservation program areas outlined in the Application. Rather, the Companies are requesting Commission approval to treat all incremental EEC expenditures as equivalent to capital as outlined in Sections 1.4.2 and 6.12 of the Application. Please also see BCUC IR 1.10.2 for further discussion of capitalization.

66.0 Reference: Exhibit B-1, Appendix 1, CPR, DHW, p. 17

66.1 What are the assumed input and output water temperatures? What would the savings be, and how would it affect the TRC of DHW programs if it were assumed the tank temperature was 49 degrees centigrade?

Response:

As noted on page 17 of the Residential Section of Appendix A, the UEC estimates assume a temperature rise of 45ºC. It is unclear if the question refers to a temperature *rise* of 49ºC, however, changing assumptions about the temperature rise would have minimal effect on TRC, since the amount of hot water consumed has a significantly greater effect. That is, more efficient end uses for hot water that is created by a water heating device has a greater effect on energy savings than changing assumptions about a temperature rise. This can be seen in Exhibit E5 on page E-vii of the Residential Section of Appendix A where Measure R-4, "DHW Load Reduc" has a most likely Achievable Potential of 148 TJ as opposed to Measure R3, "Efficient DHW Eqpt", which has a most likely Achievable Potential of 8 TJ.

67.0 Reference: Exhibit B-1, Appendix 1, CPR, Changing Use, p. 38

67.1 Please summarize the use data for major appliance end-uses from the 1980s to the present in support of the assumption that further appliance efficiencies will be relatively minor over the forecast period. Please provide the same information for furnaces.

Response:

Included in Attachment 67.1 is the Natural Resources Canada Survey of Housing Energy Use.

68.0 Reference: Exhibit B-1, Appendix 1, CPR, Windows, p. 55

68.1 Please prepare a table for a window of a standard size (and state the size) showing the R-value of the window, annual energy saved in GJ and dollars, and installed cost for each different quality of window.

Response:

There are a multitude of combinations of window sizes and feature of windows. For the calculations used in the Terasen Gas Residential CPR, please see pages B-7 and B-8 of the Residential Section of Appendix A. Please note that B-7 is for high-performance windows, and that B-8 is for Super High Performance Windows. The distinction is addressed on page 55 of the Terasen Gas Residential CPR.

68.2 Please provide the source and an extract from the referenced Marbek report that estimated a 30 year life for windows. Is this life the same for all types?

Response:

Window life was based by Marbek on information compiled from manufacturers during the study cited.

69.0 Reference: Exhibit B-1, Appendix 1, CPR, Heat Pumps, p. 73

69.1 What is the simple payback for the customer of an electric heat pump vs. the gas furnace with A/C? Please state all efficiency assumptions and show the calculation.

Response:

Please refer to the Application, Appendix 1, page C-1 of the Residential Section.

70.0 Reference: Exhibit B-1, Appendix 1, Marbek Residential Sector Report (Apr.2006), p. E-vii, and Exhibit B-1, Executive Summary, p. E-3

70.1 "Energy markets in Canada and worldwide have experienced a number of extraordinary events in the recent past. As a result, natural gas costs have risen substantially since the start of this CPR. As current natural gas costs are higher than those used in this analysis, the benefits of efficiency measures may be understated while the benefits of fuel choice measures may be overstated. Within the limits of the time and resources available, this CPR has attempted to accommodate the increasing natural gas prices by applying a "high level" price sensitivity analysis to the measures screening process. Efficiency measures that were close but did not initially pass the measures TRC test have been included in the Economic Potential scenario. (B-1, Appendix 1, p. E-vii)"

"In 2005, the Terasen Utilities retained Marbek Resource Consultants Ltd. ("Marbek") to undertake a Conservation Potential Review ("CPR"), a review which had been contemplated in the 2004 Resource Plans for TGI and TGVI. The CPR was received by the Companies in 2006. The findings of the CPR were further refined through consultation with Habart and Associates Consultants ("Habart"). The Companies also developed "portfolio level" initiatives in addition to traditional energy efficiency and fuel switching programs. The strategies outlined in this Application, and the expenditures for which approval is being sought, are based to a significant degree on the findings of the CPR and the subsequent work undertaken with Habart. (B-1, E-3)"

70.2 How do the prices used in the April 2006 Marbek CPR study and the Habart Report compare to current natural gas prices, and those expected for the test period?

Response:

The tables below show customer prices for gas and electricity from the CPR, from the Habart Report and at the current time. A rate of inflation of 1.9% for natural gas and 2% for electricity was applied in the analysis performed to generate the proposed expenditure, as can be seen on the "Inputs" pages of the workbooks filed in response to BCUC IR 1.56.2.

Customer Energy Prices (CPR)*

	Residential		Commercial	
Customer Energy Prices	Natural Gas $/MJ	Electricity $/MJ	Natural Gas $/MJ	Electricity $/MJ
Vancouver Island	$0.0132	$ 0.0169	$0.0113	$0.0135
Lower Mainland	$0.0105	$ 0.0169	$0.0099	$0.0135
Interior	$0.0104	$ 0.0169	$0.0098	$0.0135

Customer Energy Prices (Habart Report January 2007)

	Residential		Commercial	
Customer Energy Prices	Natural Gas $/MJ	Electricity $/MJ	Natural Gas $/MJ	Electricity $/MJ
Vancouver Island	$0.0137	$ 0.0176	$0.0118	$0.0155
Lower Mainland	$0.0113	$ 0.0176	$0.0107	$0.0155
Interior	$0.0113	$ 0.0176	$0.0108	$0.0155

Customer Energy Prices (July 2008)

	Residential		Commercial	
Customer Energy Prices	Natural Gas $/MJ	Electricity $/MJ	Natural Gas $/MJ	Electricity $/MJ
Vancouver Island	$0.0143	$ 0.0182	$0.0125	$0.0161
Lower Mainland	$0.0138	$ 0.0182	$0.0132	$0.0161
Interior	$0.0138	$ 0.0182	$0.0133	$0.0161

70.3 Are each of the measures proposed in the Application such that they would pass the TRC test, given current natural gas prices, and the range of prices expected over the test period?

<u>Response:</u>

Yes, each of the measures proposed in the Application passes the TRC test. In fact, cost-benefit analysis done today would show a higher TRC than is presented here, as natural gas commodity costs have increased since the analysis was done. TRC results by measure from the analysis can be viewed on the “Measure data and benefit analysis” pages of the workbooks filed in response to BCUC IR 1.56.2.

71.0 Reference: Exhibit B-1, Appendix 2, B-3 DSM Status Report, p. 4 - DSM Evaluation

71.1 Please file “2003 Residential DSM Campaign Evaluation”, Habart & Associates Ltd., August 2004 mentioned in Appendix 2, page 4.

Response:

Please refer to Attachment 71.1.

71.2 In Appendix 2, page 2 of the TGI 2007 Annual Review it stated: “Terasen Gas has launched an evaluation of the Energy Start Heating Upgrade program that ran from September 2005 to March 2007, and the first results are anticipated to be available early in 2008 and will be included in next year’s Annual Review.”

71.2.1 Is the evaluation complete? If so, please file the report. If not, when will it be complete?

Response:

Please refer to Attachment 71.2.1.

TGI launched an evaluation of the Energy Star Heating System Upgrade Program in Q2, 2007. The project consisted of two phases, the first phase addressed factors influencing program participation, free riders, program-induced changes to furnace and furnace blower operating behaviours, customer and trade ally satisfaction, and preliminary estimates of program savings and reductions in carbon dioxide emissions. Fieldwork and analysis for this phase were conducted during second half of 2007 and the report was finalized by Q2, 2008. The report is attached.

The second phase of the evaluation will undertake a billing analysis of participating and non-participating customers to firm up estimates of program savings. This latter phase will commence after study participants have accumulated sufficient billing history (one full heating season) with their new furnace. The phase two evaluation will also use data gathered from the market research conducted under the first phase of the evaluation plan. The analysis for this work will commence in August, 2008 and the results will be available by Q4, 2008.

71.2.2 If the evaluation is not complete please file the preliminary results.

Response:

The evaluation of the Energy Star Heating System Upgrade Program was completed except for the billing analysis phase. Please also refer to the response to BCUC IR 1.71.2.1

71.3 Please provide a list (description and dates) of the various DSM performance assessments conducted on Terasen's DSM programs in the last five years.

Response:

Please refer to the following table.

Report Name	Report Date	Consultant	Program Dates	Description
2002 Residential Heating System Upgrade Program Evaluation	Oct 2003	Habart & Associates	Aug 1, 2002 to Nov 30, 2002	The objective of this study was to provide an impact, process and market evaluation of the 2002 program. In this report, the free rider rate was calculated based on participants' response to questions about the importance of the program in their decision to replace the furnace, and the impact numbers were developed based on engineering estimates. Once sufficient billing data is available, the impact estimates will be re-developed based on the billing data, and the free rider estimates will be refined using discrete choice methods. This analysis will be done in the fall of 2004.
Billing Analysis - 2002 Residential Heating System Upgrade Program Evaluation	Jul 2004	Habart & Associates	Aug 1, 2002 to Nov 30, 2002	This report is an addendum to "Final Report – 2002 Residential Heating System Upgrade Program Evaluation", October 2003. That report provides the basic summary and evaluation of Terasen's 2002 program, except for the Discrete Choice Analysis to determine attribution, and the billing analysis to determine the energy impact of the program, both of which are covered in this report.
2001 Winter Bill Saver Program High Efficiency Heating System Offer	Dec 2003	Habart & Associates	Sep 1, 2001 to Nov 30, 2001	The purpose of this study is to undertake a comprehensive impact evaluation of the 2001 High Efficiency Heating System Offer. In undertaking this work we draw on previous research undertaken by BC Gas and apply advanced statistical methods to estimate program impacts. In particular, we use discrete choice modelling in the form of probit analysis to examine the determinants of program participation and program attribution and analysis of weather normalized pre/post consumption change with a comparison group to estimate gross impacts.
2001 Summer Furnace Tune-Up Program	Dec 2003	Habart & Associates	May 22, 2001 to Sep 15, 2001	The purpose of this study is to undertake a comprehensive impact evaluation of the 2001 BC Gas Furnace Tune–up Program. Several features of this work should be noted: 1) detailed market research undertaken by BC Gas is a major source of information for the analysis; 2) discrete choice modelling in the form of probit analysis is used to examine the determinants of program participation and program attribution; 3) gross impact of measure installation is based on analysis of weather normalized consumption combined with engineering algorithms; 4) impact on carbon dioxide emissions is based on engineering algorithms.
2001 Winter Bill Saver Program Weatherization and Insulation Offer	Dec 2003	Habart & Associates	Sep 15, 2001 to Nov 30, 2001	The purpose of this study is to undertake a comprehensive impact evaluation of the 2001 BC Gas Weatherization and Insulation Offer. Several features of this work should be noted: 1) detailed market research undertaken by BC Gas is a major source of information for the analysis; 2) discrete choice modelling in the form of probit analysis is used to examine the determinants of program participation and program attribution; 3) gross impact of measure installation is based on analysis of weather normalized pre/post consumption change with a comparison group.
BC Gas – Efficient Boiler Program Impact Evaluation	Jun 2003	Habart & Associates	1995 to 2001	The BC Gas Efficient Boiler Program provided customer incentives and technical advice to encourage the installation of mid efficiency and high efficiency boilers in new buildings and retrofit situations. This report summarizes the result of an impact evaluation of the Efficient Boiler Program.
Impact of Terasen Gas / Energy Star Heating System Upgrade (2003) Program	Aug 2004	Habart & Associates	Sep 1, 2003 to Dec 15, 2003	The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. This report provides a process, market and impact evaluation of the Heating System Upgrade Program.
Impact of Terasen Gas Pilot Fireplace Program (2004)	Mar 2005	Habart & Associates	Jun 15, 2004 to Sep 15, 2004	This report provides a process, market and impact evaluation of the pilot Fireplace Upgrade Program. The purpose of the evaluation is to review the performance of both the program and of the fireplaces themselves. The evaluation is structured in two phases, the first to provide program process evaluation results and preliminary impact estimates as soon as practical after the end of the program, while the second phase will occur later in 2005 when sufficient billing data is available to better understand the load impact. NB: SECOND PHASE NOT DONE DUE TO RESULTS OF FIRST PHASE.
Evaluation of Terasen's 2005-07 Heating System Upgrade Program	Apr 2008	Habart & Associates	Sep 2005 to Mar 2007	This report summarizes the findings from the first phase of a two-phase evaluation of Terasen's 2005-07 Heating System Upgrade Program. The program offered a financial incentive towards the purchase of an Energy Star® qualified high efficiency natural gas furnace or boiler, and an additional incentive if the customer chose a qualifying furnace / boiler equipped with a variable speed drive (VSM) motor. NB: The second phase of the evaluation (scheduled for autumn 2008) is to conduct a billing analysis of participating and non-participating customers to firm up estimates of program savings. This latter phase will commence once study participants have accumulated sufficient billing history (one full heating season) with their new furnace. Phase two will also use data gathered from the market research conducted under phase one of the evaluation.
Terasen Gas Evaluation of Commercial Energy Assessments	Q4, 2008 (in progress)	Friuch Consulting	Feb 2003 to June 2007	Commercial Energy Assessment Program provides energy assessments to commercial and small industrial customers upon request. The current version of the program was launched in mid-2005; the program offers a thorough energy audit conducted by third-party energy consultants at no charge to qualified program participants. Over 100 assessments are typically conducted each year for various customers across the province. In order to assess the effectiveness of this initiative, Terasen Gas has hired a third-party consultant to perform an evaluation of this program to measure its effectiveness. The study results will be available in the fourth quarter of 2008.

71.4 Please discuss the merit (pros and cons) for an independent audit of the DSM Evaluation Report. Does the Ontario Energy Board require Union Gas and Enbridge Gas Distribution to have an independent audit of their DSM Evaluation Reports?

Response:

One of the working groups for the BCPECE is the Evaluation working group. This group will be bringing forward a proposal to the Commission on the appropriate Measurement, Evaluation and Reporting protocols for British Columbia utilities. The Companies are participating in this working group, and believe that participation in the group is the appropriate way for protocols to be developed that will be applied in a coordinated way across all the Utilities in BC. At the time of writing, the first meeting of this working group has not yet been convened. However the Companies have the following comments.

In the context of DSM activities, evaluation and measurement is a process by which programs are reviewed for effectiveness that includes program impacts and verification of energy savings. The information obtained during program evaluation can be used to improve future programs.

The role of an audit is to:

- Verify the validity TRC and other DSM test results
- Verify the financial results in the Evaluation Report
- Review the reasonableness of any input assumptions
- Recommend any forward looking evaluation work to be considered

Program evaluations and audits can be conducted in-house or outsourced to an independent third-party resource. Independent DSM audits, similar to independent financial audits, provide unbiased perspective. Independent auditors may have unique skills which may not be available within the organization and allow the organization to leverage the resources. They also provide a fresh perspective on programs and assumptions and may help to avoid the repetition of errors; however, the costs for an independent audit may be higher and auditors may not be familiar with the program as well as the DSM staff would be. Depending on the regulatory environment, independent audits may duplicate the work of the regulator, i.e. where the regulator undertakes audit and measurement activities.

The Ontario Energy Board require Union Gas and Enbridge Gas Distribution to have an independent audit of their DSM Evaluation Reports as per OEB's decision EB-2006-0021; (Please refer to Attachment 71.4, EB-2006-0021, issues 9.1 through 9.4 deal with evaluation and audit requirements).

72.0 Reference: Exhibit B-1, Appendix 9 Habart Report, Base Year, p. 4

A number of questions in sections 72 to 75 indicate that the process used to develop the Conservation Potential were not clearly understood from the "Background" Section provided on p. 3 of the Habart report.

In order to develop the Conservation Potential in a cost effective manner, the approach taken was to start with the comprehensive list of measures from the CPR and then to narrow them down to those that are likely to be successful before developing program concepts. The concept development stage is more costly.

The measure screening, covered in Section 3 of the report, is performed by dividing the expected energy cost savings by the incremental cost. As such, it is an estimation of the cost effectiveness of the measure, not of a program to promote the measure.

The measures that pass the screen are then reviewed to determine if they are candidates for programs. Some measures with positive benefit / cost ratios may be dropped at this stage if they would likely fail as a program because of issues such as a high market share of the efficient product which would result in a high free rider rate and hence an inadequate TRC.

Program concepts are then developed for the remaining measures. This process includes:

1. Estimating the program development costs
2. Determining the incentive level
3. Estimating program uptake rate
4. Estimating the likely free rider rate
5. Estimating the program operating costs, including administration, marketing, training and evaluation.

Finally the program estimates are put into the full benefit / cost model and the program is tested in the workbook model.

72.1 Was the change to the "more current natural gas and electricity marginal costs and rates" the only change made for re-screening? If not, what other changes were made?

Response:

As part of the Habart review, Marbek Resource Consultants was asked to re-run the measures included in the original CPR with the following changes:

- For all of the measures, use the revised avoided costs and rate data for both natural gas and electricity

- For selected measures, also revise costs and performance data to reflect current conditions.

Habart and Associates provided Marbek with both the revised avoided cost data and the updated measure cost and performance data. Marbek incorporated the new input into the CPR measures model and produced the updated set of outputs. Section 2 of the "Terasen Gas CPR Measure Update" Report, included as an appendix to the Habart report, contains a summary of the revised costs and performance data.

72.2 Was the base year updated, and if not would updating the base year affect the results and how?

Response:

The base year in the CPR analysis was not updated as part of the Re-Screening process. The CPR had been completed less than a year before the Re-Screening and significant changes were not anticipated (in either the shares of EE products or the growth rate of the customer base).

73.0 Reference: Exhibit B-1, Appendix 9, Habart Report, Residential Retrofit and New Construction, pp. 6,7

73.1 For each of the measures shown in Exhibits 3.1 and 3.2 please provide a table showing the value of each DSM test disaggregated by individual component showing measure costs, incentives, administration cost, savings in GJ and dollars per unit, electricity savings in kW.h and dollars, number of customers participating, penetration rates and lost revenue.

<u>Response:</u>

Exhibits 3.1 and 3.2 show the results of the re-screening tests. As discussed above, this analysis is done at the start of the DSM strategy process to determine which technologies appear to be cost effective and therefore worthwhile to include in program concept development. As such, they only include the costs and savings for the technologies, and the resultant benefit / cost ratio.

The following tables show the costs and savings both natural gas and electricity for the analysis completed for Exhibits 3.1 and 3.2: tables supporting Exhibits 3.1 and 3.2 are included below.

IR 73.1 Residential New Construction – Energy Efficiency, Single Family Dwelling

	Vancouver Island SFD						Lower Mainland SFD						Interior SFD					
	Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings (MJ/yr)		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings (MJ/yr)		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings (MJ/yr)		Participant Impact	
			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio
Air Sealing	I	$ 700	5,573	346	$82.43	0.8	I	$700	8,855	346	$106.14	1.2	I	$ 700	7,059	346	$ 85.85	1
High Perf. Windows	I	$ 900	9,732	634	$121.12	1.2	I	$900	9,536	634	$118.91	1.2	I	$ 900	11,264	634	$ 138.43	1.3
E* Furnace	I	$ 600	7,709	0	$105.62	1	I	$600	12,249	0	$138.42	1.6	I	$ 600	9,765	0	$ 110.34	1.2
Showerhead / Faucets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pipe Insulation	F	$ 4	180	0	$2.47	1.8	F	$4	180	0	$2.03	1.8	F	$ 4	180	0	$ 2.03	1.8
E* Dishwashers	I	$ 50	2,080	123	$30.67	3.3	I	$50	2,534	123	$30.80	3.9	I	$ 50	2,080	123	$ 25.67	3.2
E* Clothes Washers	I	$ 100	2,827	130	$41.01	2.2	I	$100	3,371	130	$40.38	2.6	I	$ 100	2,774	130	$ 33.63	2.2
Pool Cover	F	$ 350	18,334	0	$251.18	3	F	$350	21,007	0	$237.38	3.4	F	$ 350	22,411	0	$ 253.25	3.6
EE Fireplaces	I	$ 200	4,891	0	$67.01	1.7	I	$200	4,891	0	$55.27	1.7	I	$ 200	4,891	0	$ 55.27	1.7
EGNH 80	I	$ 4,836	49,714	6178	$789.81	1.3	I	$3,606	34,946	5,568	$492.89	1.3	I	$ 3,716	39,954	6,960	$ 573.98	1.5

IR 73.1 Residential New Construction – Energy Efficiency, Row Houses

	Vancouver Island RH						Lower Mainland RH						Interior RH					
	Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings		Participant Impact	
			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio
Air Sealing	I	$ 700	4,448	173	$ 63.98	0.6	I	$ 700	6,747	173	$ 79.28	0.9	I	$ 700	5,269	173	$ 62.59	0.7
High Perf. Windows	I	$ 360	3,892	317	$ 49.56	1.2	I	$ 360	3,816	317	$ 48.70	1.2	I	$ 360	4,507	317	$ 56.50	1.4
E* Furnace	I	$ 600	6,153	0	$ 84.30	0.8	I	$ 600	9,333	0	$ 105.46	1.2	I	$ 600	7,289	0	$ 82.37	0.9
Showerhead / Faucets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pipe Insulation	F	$ 4	180	0	$ 2.47	1.8	F	$ 4	180	0	$ 2.03	1.8	F	$ 4	180	0	$ 2.03	1.8
E* Dishwashers	I	$ 50	1,738	95	$ 25.48	2.7	I	$ 50	2,014	95	$ 24.44	3.1	I	$ 50	1,641	95	$ 20.23	2.6
E* Clothes Washers	I	$ 100	2,320	98	$ 33.50	1.8	I	$ 100	2,659	98	$ 31.76	2.1	I	$ 100	2,140	98	$ 25.90	1.7
Pool Cover	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EE Fireplaces	I	$ 200	4,891	0	$ 67.01	1.7	I	$ 200	4,891	0	$ 55.27	1.7	I	$ 200	4,891	0	$ 55.27	1.7
EGNH 80	I	$ 228	6,498	1610	$ 117.36	4.6	I	$ 793	4,397	1,687	$ 79.38	1.1	I	$ 3,157	26,073	3,969	$ 364.48	1.1

IR 73.1 - Residential Retrofit – Energy Efficiency, Single Family Dwelling

	Vancouver Island SFD						Lower Mainland SFD						Interior SFD					
	Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings (MJ/yr)		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings (MJ/yr)		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings (MJ/yr)		Participant Impact	
			Natural Gas	Electricity	Annual Costs	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs	B/C Ratio
Air Sealing	F	$ 900	7,629	259	$ 109.08	0.8	F	$ 900	12,037	259	$ 140.58	1.2	F	$ 900	9,410	259	$ 110.90	1.0
High Perf. Windows	I	$ 600	6,488	130	$ 91.17	1	I	$ 600	6,358	130	$ 74.13	1	I	$ 600	7,510	130	$ 87.14	1.2
E* Furnace	I	$ 600	10,331	0	$ 141.53	1.3	I	$ 600	16,300	0	$ 184.19	2.1	I	$ 600	12,743	0	$ 143.99	1.6
Showerhead / Faucets	F	$ 25	2,011	0	$ 27.55	5.1	F	$ 25	2,453	0	$ 27.71	6.2	F	$ 25	2,011	0	$ 22.72	5.1
Pipe Insulation	F	$ 4	180	0	$ 2.47	1.8	F	$ 4	180	0	$ 2.03	1.8	F	$ 4	180	0	$ 2.03	1.8
E* Dishwashers	I	$ 50	2,120	147	$ 31.64	3.4	I	$ 50	2,586	147	$ 31.81	4.1	I	$ 50	2,120	147	$ 26.55	3.4
E* Clothes Washers	I	$ 100	2,877	150	$ 42.06	2.3	I	$ 100	3,434	150	$ 41.44	2.7	I	$ 100	2,824	150	$ 34.54	2.3
Pool Cover	F	$ 350	18,334	0	$ 251.18	3	F	$ 350	21,007	0	$ 237.38	3.4	F	$ 350	22,411	0	$ 253.25	3.6
EE Fireplaces	I	$ 200	4,891	0	$ 67.01	1.7	I	$ 200	4,891	0	$ 55.27	1.7	I	$ 200	4,891	0	$ 55.27	1.7
EGNH 80	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

IR 73.1 - Residential Retrofit – Energy Efficiency, Row Houses

	Vancouver Island RH						Lower Mainland RH						Interior RH					
	Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings		Participant Impact	
			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio
Air Sealing	I	$ 900	4,538	173	$ 65.21	0.5	I	$ 900	6,521	173	$ 76.73	0.7	I	$ 900	4,912	173	$58.55	0.5
High Perf. Windows	I	$ 240	2,594	86	$ 37.06	1.1	I	$ 240	2,544	86	$ 30.27	1.1	I	$ 240	3,005	86	$35.48	1.2
E* Furnace	I	$ 600	6,145	0	$ 84.18	0.8	I	$ 600	8,831	0	$ 99.79	1.1	I	$ 600	6,652	0	$75.17	0.8
Showerhead / Faucets	F	$ 25	1,680	0	$ 23.02	4.3	F	$ 25	1,950	0	$ 22.03	4.9	F	$ 25	1,587	0	$17.93	4.0
Pipe Insulation	F	$ 4	180	0	$ 2.47	1.8	F	$ 4	180	0	$ 2.03	1.8	F	$ 4	180	0	$2.03	1.8
E* Dishwashers	I	$ 50	1,771	114	$ 26.27	2.8	I	$ 50	2,055	114	$ 25.23	3.2	I	$ 50	1,673	114	$20.91	2.7
E* Clothes Washers	I	$ 100	2,361	113	$ 34.34	1.9	I	$ 100	2,708	113	$ 32.58	2.1	I	$ 100	2,178	113	$26.60	1.7
Pool Cover	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EE Fireplaces	I	$ 200	4,891	0	$ 67.01	1.7	I	$ 200	4,891	0	$ 55.27	1.7	I	$ 200	4,891	0	$55.27	1.7
EGNH 80	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Measures that pass this screening are then considered as candidates for programs and estimates are developed for the other program parameters such as program costs, incentive levels, uptake rates, etc. Once the program estimates have been made, the costs and benefits are then input to the model and the "California Standard Tests" are developed.

The budget estimates and subsequent expenditure request for Residential Energy Efficiency in the Application were developed based upon the program development work described in the paragraph above. The analysis on which the expenditure request was based has been provided the workbooks attached to the response to BCUC IR 1.56.2.

73.2 Please confirm that the cost associated with developing and managing programs is not included.

Response:

The costs of developing and managing the costs of the programs was not included in the analysis in Exhibits 3.1 and 3.2, as these tables only summarize the costs and benefits of the individual measures. However these costs WERE included in the workbooks filed in response to BCUC IR 1.56.2, and the expenditure request in the Application is based upon the information contained within the workbooks that were filed in response to BCUC IR 1.56.2.

73.3 Were the estimated savings for each of natural gas and electricity adjusted for free ridership? If yes, please describe in detail how free ridership was estimated for each program and the free ridership rates.

Response:

Estimates for measure energy savings in Exhibit 3.1 and 3.2 do not include any adjustment for free riders. This is done at a later stage when program concepts are developed. There are two sets of workbooks filed in response to BCUC IR 1.56.2 – one showing an adjustment for free riders, and one without an adjustment for free riders. The free rider rates can be found in the individual measure sheets in the workbooks.

A number of different approaches have been used to estimate the free rider rate (FRR) that may be associated with the individual program.

1. In cases where Terasen Gas has operated a program which has been evaluated, the free rider rate from the evaluation has been used. In the evaluations, the FRR has typically been determined by a combination of information from: a customer survey; a

trade ally survey; and in some cases by discrete choice analysis modeling using participant and non-participant data.

2. For other programs, the approach has been to estimate the sales of energy efficient products sold in the specific market and then estimate the level of projects program sales. The ratio of existing energy efficient products sold prior to the program and the estimated program sales provides the estimated FRR rate.
3. In some cases, other utilities have operated similar programs in the same or similar marketplaces. In this case, the FRR from the other program has been used.
4. In some cases, "expert" opinion has been used. This may be from industry people outside of the utility or from Terasen Gas field staff who work closely with the trades and major customers.

73.4 Were the results adjusted for cross-over effects such as an estimate of the impact of E* Dishwashers might have in increasing the load on the furnace? If yes, please describe this analysis in detail for each program describing how the savings estimates were derived for each program and in what amount.

Response:

The only program where cross-over effects was explicitly considered was for the natural gas fireplaces where the effects of replacing a decorative logset with an efficient fireplace on the energy use of the heating system (both electric and natural gas) were considered in the impact analysis. The analysis was done using Hot2000, The methodology is outlined below:

As part of the evaluation of the Terasen Gas Pilot Fireplace Program (2004) a series of models were set up in HOT2000 to determine the cross effects between the more efficient natural gas fireplace (in the program decorative logsets were replaced by fireplaces with an efficiency of 55% or better). Four models were developed:

- Single family dwelling with natural gas main heating
- Single family dwelling with electric main heating
- Apartment with natural gas main heating
- Apartment with electric main heating

The HOT2000 model has internal logic to determine how the increased heat from the fireplace reduces the load on the central heating system. HOT2000 indicates that internal heat gains offset primary space heating by a factor of 0.4. This reflects the imperfect nature of heat distribution between the fireplace and thermostat that controls the main heating system. A series of model runs were undertaken to understand the net impact of the new fireplace on total space heating requirements within each type of unit.

Crossover effects from the impact of E* dishwashers on furnace loads were not considered, as the reduction in heat output from an E* dishwasher is unlikely to be of a sufficient magnitude to affect the thermostat controlling the furnace.

73.5 Were cross-over impacts between gas and electricity considered? If yes, please describe this analysis in detail for each program describing how the savings estimates were derived for each program and in what amount.

Response:

See 73.4 above. Cross-over effects were only explicitly considered for the fireplace pilot program, and were considered for both the impact on the natural gas and electric central heating system. There may be cross over effects from BC Hydro's lighting programs and E* appliance programs in that, as the efficiency of these products increases, the heat produced by them will decrease. Thus additional heat will be required from the main and secondary heating sources. This may represent additional load on the natural gas system, but has not been analyzed as it is exogenous to the proposed Energy Conservation programs.

74.0 Reference: Exhibit B-1, Appendix 9, Habart Report, Residential Fuel Substitution, p. 8

74.1 For each of the measures shown in Exhibits 3.3 and 3.4 please provide a table showing the value of each DSM test disaggregated by individual component showing measure costs, incentives, administration cost, savings in GJ and dollars per unit, electricity savings in kW.h and dollars, number of customers participating, penetration rates and lost revenue.

<u>Response:</u>

Exhibits 3.3 and 3.4 show the results of the re-screening tests. As discussed above, this analysis is done at the start of the DSM strategy process to determine which technologies appear to be cost effective and therefore worthwhile to include in program concept development. As such, they only include the costs and savings for the technologies, and the resultant benefit / cost ratio.

The following tables show the costs and savings both natural gas and electricity for the analysis completed for Exhibits 3.3 and 3.4:34

IR 74.1 - Residential New Construction – Fuel Substitution, Single Family Dwelling

	Vancouver Island SFD						Lower Mainland SFD						Interior SFD					
	Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy		Participant Impact	
			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio
Furnace Fuel Choice	I	$ 2,050	-38,732	39,475	164.13	2	I	$ 2,050	-61,543	62,723	$ 408.50	2.3	I	$ 2,050	-49,060	50,001	$ 325.64	2
DHW Fuel Choice	I	$ 350	-18,790	10,334	-75.54	1.3	I	$ 350	-22,891	12,590	$ (37.08)	1.3	I	$ 350	-18,790	10,334	$ (30.44)	1.2
Range Fuel Choice	I	$ -	-7,598	3,039	-50.6	1.3	I	$ -	-9,260	3,704	$ (39.45)	1.3	I	$ -	-7,598	3,039	$ (32.37)	1.2
Dryer Fuel Choice	I	$ -	-3,756	2,782	-2.49	2.4	I	$ -	-4,368	3235	$ 7.58	2.4	I	$ -	-3,605	2670	$ 6.26	2.2

IR 74.1 – Residential New Construction – Fuel Substitution, Row Houses

	Vancouver Island RH						Lower Mainland RH						Interior RH					
	Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy		Participant Impact	
			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio
Furnace Fuel Choice	I	$ 2,050	-30,914	31,507	$ 131.00	1.8	I	$ 2,050	-46,891	47,790	$ 311.24	2.1	I	$ 2,050	-36,622	37,325	$ 243.09	1.8
DHW Fuel Choice	I	$ 350	-15,699	8,634	$ (63.11)	1.2	I	$ 350	-18,196	10,008	$ (29.48)	1.3	I	$ 350	-14,827	8,155	$ (24.02)	1.1
Range Fuel Choice	I	$ -	-6,185	2,474	$ (41.19)	1.3	I	$ -	-7,182	2,873	$ (30.60)	1.3	I	$ -	-5,841	2,336	$ (24.88)	1.2
Dryer Fuel Choice	I	$ -	-3,018	2236	$ (2.00)	2.4	I	$ -	-3,411	2527	$ 5.92	2.4	I	$ -	-2,704	2,003	$ 4.70	2.2

IR 74.1 – Residential Retrofit – Fuel Substitution, Single Family Dwelling

	Vancouver Island SFD						Lower Mainland SFD						Interior SFD					
			Annual Energy		Participant Impact				Annual Energy		Participant Impact				Annual Energy		Participant Impact	
	Measure Capital & Installation Cost F=Full I=Incremental		Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio	Measure Capital & Installation Cost F=Full I=Incremental		Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio	Measure Capital & Installation Cost F=Full I=Incremental		Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio
Furnace Fuel Choice	I	-400	-53,243	54,037	$ 221.63	3.4	I	-400	-84,009	85,263	$ 551.32	3.3	I	-400	-65,675	66,655	$ 431.00	3.1
DHW Fuel Choice	I	1,250	-19,150	10,533	$ (76.98)	0.8	I	1250	-23,358	12,847	$ (37.84)	0.9	I	1250	-19,150	10,533	$ (31.02)	0.7
Range Fuel Choice	I	150	-7,786	3,114	$ (51.85)	1.0	I	150	-9,489	3,796	$ (40.42)	1.1	I	150	-7,786	3,114	$ (33.17)	1.0
Dryer Fuel Choice	I	150	-3816	2827	$ (2.53)	1.6	I	150	-4438	3287	$ 7.71	1.7	I	150	-3663	2713	$ 6.36	1.4

IR 74.1 – Residential Retrofit – Fuel Substitution, Row Houses

	Vancouver Island RH						Lower Mainland RH						Interior RH					
			Annual Energy		Participant Impact				Annual Energy		Participant Impact				Annual Energy		Participant Impact	
	Measure Capital & Installation Cost F=Full I=Incremental		Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio	Measure Capital & Installation Cost F=Full I=Incremental		Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio	Measure Capital & Installation Cost F=Full I=Incremental		Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio
Furnace Fuel Choice	I	-400	-31,669	32,142	$ 131.83	3.5	I	-400	-45,513	46,192	$ 298.69	3.4	I	-400	-34,285	34,797	$ 225.00	3.2
DHW Fuel Choice	I	1,250	-16,000	8,800	$ (64.32)	0.7	I	1250	-18,567	10,212	$ (30.08)	0.8	I	1250	-15,112	8,311	$ (24.48)	0.6
Range Fuel Choice	I	150	-6,338	2,535	$ (42.21)	1.0	I	150	-7,360	2,944	$ (31.35)	1.0	I	150	-5,985	2,394	$ (25.50)	0.9
Dryer Fuel Choice	I	150	-3,067	2272	$ (2.03)	1.5	I	150	-3,466	2,567	$ 6.02	1.5	I	150	-2,747	2,035	$ 4.77	1.3

Measures that pass this screening are then considered as candidates for programs and estimates are developed for the other program parameters such as program costs, incentive levels, uptake rates, etc. Once the program estimates have been made, the costs and benefits are then input to the model and the "California Standard Tests" are developed.

The budget estimates and subsequent expenditure request for Residential Energy Efficiency in the Application were developed based upon the program development work described in the paragraph above. The analysis on which the expenditure request was based has been provided in the workbooks attached to the response to BCUC IR 1.56.2.

74.2 Please confirm that the cost associated with developing and managing programs is not included.

Response:

As noted in the response to BCUC IR 1.73.2 above, the costs of developing and managing the costs of the programs was not included in the analysis in the Habart report, as these tables only summarize the costs and benefits of the individual measures. However these costs WERE included in the workbooks filed in response to BCUC IR 1.56.2, and the expenditure request in the Application is based upon the information set out in the workbooks that were filed in response to BCUC IR 1.56.2.

74.3 Were the estimated savings for each of natural gas and electricity adjusted for free ridership? If yes, please describe in detail how free ridership was estimated for each program and the free ridership rates.

Response:

Please refer to the response to BCUC IR 1.73.3 above.

74.4 Were the results adjusted for cross over effects? If yes, please describe this analysis in detail for each program describing how the savings estimates were derived for each program and in what amount.

Response:

Cross over effects were not considered for fuel substitution. As these programs encourage a change of fuel for furnaces, hot water, cooking and cloths drying, it is unlikely that there would be any measureable cross over effects.

74.5 Were crossover impacts between gas and electricity considered? If yes, please describe this analysis in detail for each program describing how the savings estimates were derived for each program and in what amount.

Response:

Cross over effects were not considered for fuel substitution, other than the displacement of electric load, which is included. As these programs encourage the use of natural gas for the same end use, no other cross over effects are expected.

74.7 Please provide the values of the DSM tests and energy savings for the residential Fuel Substitution program if the only program was Furnace Fuel Choice.

Response:

Furnace Fuel Switching is only proposed for retrofit applications for TGVI.

Energy Savings per installation(GJ)	Total installations	RIM	Participant	TRC
(53.2)	1800	1.4	1.1	3.6

75.0 Reference: Exhibit B-1, Appendix 9, Habart Report, Commercial Energy Efficiency, p. 9

75.1 For each of the measures shown in Exhibit 3.5 please provide a table showing the value of each DSM test disaggregated by individual component showing measure costs, incentives, administration cost, savings in GJ and dollars per unit, electricity savings in kW.h and dollars, number of customers participating, penetration rates and lost revenue.

<u>Response:</u>

Exhibit 3.5 show the results of the re-screening tests. As discussed above, this analysis is done at the start of the DSM strategy process to determine which technologies appear to be cost effective and therefore worthwhile to include in program concept development. As such, they only include the costs and savings for the technologies, and the resultant benefit / cost ratio.

The following tables show the costs and savings both natural gas and electricity for the analysis completed for Exhibit 3.5: The tables supporting Exhibits 3.5 are included below.

IR 75.1 - Commercial - New Construction

	Vancouver Island						Lower Mainland						Interior					
			Annual Energy Savings		Participant Impact				Annual Energy Savings		Participant Impact				Annual Energy Savings		Participant Impact	
	Measure Capital & Installation Cost F=Full I=Incremental		Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio	Measure Capital & Installation Cost F=Full I=Incremental		Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio	Measure Capital & Installation Cost F=Full I=Incremental		Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio
New Building Construction – 30% (Large Office)	I	$ 259,910	1,503,765	2,030,400	$ 49,215.63	2.7	I	$ 259,910	1,503,765	2,030,400	$ 49,215.63	2.7	I	$ 259,910	1,503,765	2,030,400	$ 49,215.63	2.7
New Building Construction – 30% (Medium Office)	I	$ 94,850	548,775	708,588	$ 17,458.66	2.6	I	$ 94,850	548,775	708,588	$ 17,458.66	2.6	I	$ 94,850	548,775	708,588	$ 17,458.66	2.6
New Building Construction – 60%	I	$ 1,000,000	3,007,530	8,121,600	$ 161,373.65	2.5	I	$ 1,000,000	3,007,530	8,121,600	$ 161,373.65	2.5	I	$ 1,000,000	3,007,530	8,121,600	$ 161,373.65	2.5
High Performance Glazing – HIT	I	$ 160,000	640,493	540,000	$ 15,927.81	1.3	I	$ 160,000	640,493	540,000	$ 15,927.81	1.3	I	$ 160,000	640,493	540,000	$ 15,927.81	1.3
HE Boilers – Near Condensing	I	$ 36,600	640,493	0	$ 7,557.81	1.5	I	$ 36,600	685,301	0	$ 7,332.72	1.6	I	$ 36,600	685,301	0	$ 7,401.25	1.6
HE Boilers – Condensing	I	$ 69,200	1,113,900	0	$ 13,144.02	1.4	I	$ 69,200	1,113,900	0	$ 11,918.73	1.4	I	$ 69,200	1,113,900	0	$ 12,030.12	1.4
Building Recommissioning	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Next Generation BAS	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Demand Ctl Ventilation (interior)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HE Roof Top Units	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Instantaneous DHW Heaters	I	$ 2,100	73,181	0	$ 863.54	2.4	I	$ 2,100	73,181	0	$ 783.04	2.4	I	$ 2,100	73,181	0	$ 790.36	2.4
HE Condensing DHW Boiler	I	$ 17,000	1,237,667	0	$ 14,604.47	6.2	I	$ 17,000	1,237,667	0	$ 13,243.03	6.2	I	$ 17,000	1,237,667	0	$ 13,366.80	6.2
HE Condensing DHW Heater	I	$ 2,000	107,846	0	$ 1,272.58	3	I	$ 2,000	107,846	0	$ 1,153.95	3	I	$ 2,000	107,846	0	$ 1,164.74	3
Drainwater Heat Recovery	I	$ 17,500	443,055	0	$ 5,228.05	2 [1]	I	$ 17,500	443,055	0	$ 4,740.69	2 [2]	I	$ 17,500	443,055	0	$ 4,784.99	2 [3]
Pre-Rinse Spray Valves	I	$ 65	29,328	0	$ 346.08	25.5	I	$ 65	29,328	0	$ 313.81	25.5	I	$ 65	29,328	0	$ 316.75	25.5
Commercial Food Prep – Gas Range	I	$ 800	80,365	0	$ 948.31	5.7	I	$ 800	80,365	0	$ 948.31	5.7	I	$ 800	80,365	0	$ 948.31	5.7
Commercial Food Prep – Gas Broiler	I	$ 200	56,255	0	$ 663.81	15.9	I	$ 200	56,255	0	$ 663.81	15.9	I	$ 200	56,255	0	$ 663.81	15.9
Commercial Food Prep – Gas Fryer	I	$ 1,300	22,603	0	$ 266.71	1	I	$ 1,300	22,603	0	$ 266.71	1	I	$ 1,300	22,603	0	$ 266.71	1

[1, 2&3] Exhibit 3.5, p. 9 in the Review of Conservation Potential (Habart Report) was shown as 2.5 and should have been 2.0.

IR 75.1 - Commercial - Retrofit

	Vancouver Island						Lower Mainland						Interior					
	Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings		Participant Impact		Measure Capital & Installation Cost F=Full I=Incremental		Annual Energy Savings		Participant Impact	
			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio			Natural Gas	Electricity	Annual Costs Svgs ($)	B/C Ratio
New Building Construction – 30%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
New Building Construction – 60%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High Performance Glazing – HIT	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HE Boilers – Near Condensing	I	$ 44,900	974,663	0	$ 11,501.02	1.8	I	$ 44,900	974,663	0	$ 10,428.89	1.8	I	$ 44,900	974,663	0	$ 10,526.36	1.8
HE Boilers – Condensing	I	$ 86,500	1,533,177	0	$ 18,091.49	1.5	I	$ 86,500	1,533,177	0	$ 16,404.99	1.5	I	$ 86,500	1,533,177	0	$ 16,558.31	1.5
Building Recommissioning	F	$ 64,000	974,663	1,620,000	$ 36,611.02	5.3	F	$ 64,000	974,663	1,620,000	$ 36,611.02	5.3	F	$ 64,000	974,663	1,620,000	$ 36,611.02	5.3
Next Generation BAS	F	$ 80,000	487,331	810,000	$ 18,305.51	2.1	F	$ 80,000	487,331	810,000	$ 18,305.51	2.1	F	$ 80,000	487,331	810,000	$ 18,305.51	2.1
Demand Ctl Ventilation (interior)	N/A	N/A	N/A	N/A	N/A	Na	N/A	N/A	N/A	N/A	N/A	N/A	F	$5,850-$9,600	487,331-197,589	0	$5,425.51-$1,931.55	1.1 - 3.9
HE Roof Top Units	I	$ 8,996	121,800	0	$ 1,437.24	1.1	I	$ 8,996	176,400	0	$ 2,081.52	1.5	I	$ 8,996	226,800	0	$ 2,676.24	2
Instantaneous DHW Heaters	I	$ 2,100	73,181	0	$ 863.54	2.4	I	$ 2,100	73,181	0	$ 783.04	2.4	I	$ 2,100	73,181	0	$ 790.36	2.4
HE Condensing DHW Boiler	I	$ 17,000	1,237,667	0	$ 14,604.47	6.2	I	$ 17,000	1,237,667	0	$ 13,243.03	6.2	I	$ 17,000	1,237,667	0	$13,366.80	6.2
HE Condensing DHW Heater	I	$ 2,000	107,846	0	$ 1,272.58	3	I	$ 2,000	107,846	0	$ 1,153.95	3	I	$ 2,000	107,846	0	$ 1,164.74	3
Drainwater Heat Recovery	F	$ 21,000	443,055	0	$ 5,228.05	1.7	F	$ 21,000	443,055	0	$ 4,740.69	1.7	F	$ 21,000	443,055	0	$ 4,784.99	1.7
Pre-Rinse Spray Valves	F	$ 100	29,328	0	$ 346.08	16.6	F	$ 100	29,328	0	$ 313.81	16.6	F	$ 100	29,328	0	$ 316.75	16.6
Commercial Food Prep – Gas Range	I	$ 800	80,365	0	$ 948.31	5.7	I	$ 800	80,365	0	$ 948.31	5.7	I	$ 800	80,365	0	$ 948.31	5.7
Commercial Food Prep – Gas Broiler	I	$ 200	56,255	0	$ 663.81	15.9	I	$ 200	56,255	0	$ 663.81	15.9	I	$ 200	56,255	0	$ 663.81	15.9
Commercial Food Prep – Gas Fryer	I	$ 1,300	22,603	0	$ 266.71	1	I	$ 1,300	22,603	0	$ 266.71	1	I	$ 1,300	22,603	0	$ 266.71	1

Measures that pass this screening are then considered as candidates for programs and estimates are developed for the other program parameters such as program costs, incentive levels, uptake rates, etc. Once the program estimates have been made, the costs and benefits are then input to the model and the "California Standard Tests" are developed.

The budget estimates and subsequent expenditure request for Residential Energy Efficiency in the Application were developed based upon the program development work described in the paragraph above. The analysis on which the expenditure request was based has been provided in response to BCUC IR 1.56.2.

75.2 Please confirm that the cost associated with developing and managing programs is not included.

Response:

As noted in the responses to BCUC IR 1.73.2 and BCUC IR 1.74.2 above, the costs of developing and managing the costs of the programs was not included in the analysis in the Habart report, as these tables only summarize the costs and benefits of the individual measures. However these costs WERE included in the workbooks filed in response to BCUC IR 1.56.2, and the expenditure request in the Application is based upon the workbooks filed in response to BCUC IR 1.56.2.

The costs for developing and managing programs are not included in this phase.

75.3 Were the estimated savings for each of natural gas and electricity adjusted for free ridership? If yes, please describe in detail how free ridership was estimated for each program and the free ridership rates.

Response:

Please refer to the response to BCUC IR 1.73.3 above.

75.4 Were the results adjusted for cross-over effects? If yes, please describe this analysis in detail for each program describing how the savings estimates were derived for each program and in what amount.

Response:

No cross-over effects between the Commercial natural gas technologies are expected therefore this analysis was not conducted.

75.5 Were cross-over impacts between gas and electricity considered? If yes, please describe this analysis in detail for each program, describing how the savings estimates were derived for each program and in what amount.

Response:

Cross-over effects were not expected to be significant for the Commercial natural gas technologies.

However, as noted in the response to BCUC IR 1.73.5 there will be cross over effects from B C Hydro's Power Smart programs. The lighting programs will reduce the amount of heat generated into conditioned space, and will increase the natural gas load for those buildings with natural gas heat. This is exogenous to the Conservation programs and has not been analyzed.

76.0 Reference: Exhibit B-1, Appendix 9, Habart Report, Fenestration products, p. 11

76.1 The Report states: "This will transform the market for windows and doors in BC to the "economically optimum" level for the warmer parts of the province. This will also increase the level of fenestration for the colder interior, but not to the economically optimal level." Please define the term "economically optimal level".

Response:

The concept of "economically optimal" is to increase the efficiency of a measure up to the point where the lifecycle savings of the extra efficiency equals the incremental cost of the extra efficiency. In the case of fenestration, as the northern interior is colder that the remainder of the province, a higher level of energy efficiency and a higher level of cost would be "economically optimal".

77.0 Reference: Exhibit B-1, Appendix 9, Habart Report, Joint Programs, p. 12

77.1 The report states: "However, until such time as BCUC approval is received, detailed discussions about joint programs will not take place." Do the Companies agree that it would be easier to gain Commission approval if the Commission had assurance that there was not any program overlap and the resulting inefficiencies? If not, why not?

Response:

The Companies are of the view that it is the role of the BCPECE to ensure that there is no program overlap and that inefficiencies are being minimized. The Companies believe that this should provide reasonable assurance to the Commission that there will not be any material program overlap.

78.0 Reference: Exhibit B-1, Appendix 9, Habart Report, Incentives, p. 15

78.1 Incentive levels were based on 50% of incremental costs – what costs are these incremental to?

Response:

The incremental cost refers to the difference in price between the standard product and the efficient one. For example, if incremental costs for purchasing an Energy Star Dishwasher was $50, then the incentive would be 50% of incremental costs, or $25. The estimated incremental costs are the basis of the benefit / cost tests in the screening, and have been summarized in the Tables provided in the responses to BCUC IR 1.73.1, BCUC IR 1.74.1 and BCUC IR 1.75.1.

78.2 Please provide the planning assumption sheets for each measure.

Response:

Please see the response to BCUC IR 1.56.2. The planning assumption sheets for each measure can be found in the various workbooks for TGI Residential and Commercial and for TGVI Residential and Commercial, on the pages names "measure data and benefit analysis".

78.3 It is stated that a number of different approaches were taken to estimate uptake by program. Since the 50% level is determined without reference to the expected penetration, isn't it likely that some other level of incentive will elicit more response without causing undue impacts on non-participants?

Response:

Basic economics would suggest that, if the incentive was higher, more customers are likely to participate. While the higher incentive does not affect the TRC (as the incentive is a transfer payment between the utility and the program participant), it does increase the cost to the utility, and hence would affect the RIM test.

For example, if the incentive for the furnace retrofit program is increased from 50% to 100%, the RIM drops from 0.5 to 0.4. Similarly, if the Commercial near condensing boiler program incentive is similarly increased, the RIM drops from 0.6 to 0.5.

However, it is not clear how many additional customers the higher incentive would attract. In the business sector, decisions are often made based on the payback for the investment, with a 2 year payback considered a common threshold. If the incentive is increased so that the investment now yields a 1 year payback, it is not clear how many more customers would be attracted.

79.0 Reference: Exhibit B-1, Appendix 9, Habart Report, Participant Benefits, p. 17

79.1 It is stated the participant benefit "is over 9" (benefit/cost ratio). What are the participant benefits in the absence of the fuel substitution programs?

<u>Response:</u>

Please see Reference: Exhibit B-1, Appendix 11A, "Portfolio including Free Riders", page 2, 2008-2010 (2007NPV) section. This response is based on the participant benefits shown in this section of Appendix 11A, which is consistent with the funding request for the energy efficiency and fuel substitution program areas contained in the Application and with response to BCUC IR 1.56.2.

As shown in Exhibit B-1, Appendix 11A, "Portfolio including Free Riders" of the Application, page 2, 2008-2010 (2007NPV) summary in the SUBTOTALS section, both Energy Efficiency and Fuel Substitution subtotals for Residential and Commercial sectors are shown. Under the Participant Benefit Cost, 4 columns from the right hand edge of the table, the Benefit/Cost for only the Energy Efficiency programs is 8.7 while the B/C for the total portfolio is 8.5, the difference being the increase in participants' gas consumption and costs in the Fuel Substitution programs. Portfolio total participant benefits are estimated at $159.3 million while total participant benefits for energy efficiency program only are estimated at $162.5 million.

80.0 Reference: Exhibit B-1, Appendix 9, Habart Report, TRC, p. 18

80.1 In Exhibit 6.1, please explain why the total TRC of 4.0 is greater than any of its constituent parts.

Response:

Please see Reference: Exhibit B-1, Appendix 11A, "Portfolio including Free Riders", page 2, 2008-2010 (2007NPV) section.

The TRC for the total portfolio reflects the summation of the total resource costs and benefits from Residential Sector and the Commercial Sector. In the Residential Sector we see that alternate fuel and energy efficiency benefits are reduced by the gas purchases for the fuel substitution programs. The B/C for the Residential sector is 2.5.

While there is no fuel substitution in the Commercial Sector programming, the volume of savings is greater than those of the Residential Sector and there are alternate fuel benefits as well. The total costs for the sector portfolio are higher on a unit savings basis than the estimated costs for the Residential Sector. The B/C for the Commercial sector is 3.7.

When adding the Residential sector benefits to the Commercial sector benefits, the increase (approximately 34%) is much greater than the increase in costs (approximately 26%). Thus the B/C for the total portfolio is higher than any of its individual components.

Please note that the budget numbers in the Application are based upon the workbooks in Appendix 11A, which underwent revisions subsequent to the finalization of the Habart Report.

80.2 Please summarize the results of the tests in two categories, total residential and commercial, and show the number of participants and the total number of customers in each class.

Response:

Please also see Reference: Exhibit B-1, Appendix 11A, "Portfolio including Free Riders", page 2, 2008-2010 (2007NPV) section.

Please see the following table for number of Terasen customers as at December 2007.

Terasen Customers as at December 2007

	TGI	TGVI
Residential	757,261	85,030
Commercial	80,900	9,094

2008 DSM PLAN VERSION 080709 w <100% NTG

		PROGRAM					ALTERNATE	NET PRESENT VALUE				
		COSTS ($000)			SAVINGS (GJ)		Impact	Utility Benefits (Costs)		Participant Benefits (Costs)		
	Participants	Utility	Participant	Total	Gross	Net	Energy MWh	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)
2008 - 2010 (NPV 2007)												
RESIDENTIAL:												
New Construction												
Energy Efficiency	17,201	2,201	358	2,559	78,131	62,174	1,235	6,211	1,190	10,090	1,180	842
Fuel Substitution	16,101	1,844	(738)	1,106	(141,323)	(95,567)	18,337	(9,897)	19,438	(19,385)	(2,239)	13,514
Retrofit												
Energy Efficiency	31,071	5,983	2,859	8,842	206,314	148,397	2,959	15,305	2,784	26,711	3,108	2,009
Fuel Substitution	4,654	1,395	478	1,873	(109,697)	(104,685)	27,811	(11,359)	42,758	(18,156)	(1,817)	21,330
Subtotals												
Residential Energy Efficiency	48,272	8,185	3,217	11,402	284,445	210,572	4,194	21,516	3,973	36,801	4,288	2,851
Residential Fuel Substitution	20,755	3,239	(260)	2,978	(251,020)	(200,252)	46,148	(21,255)	62,196	(37,541)	(4,056)	34,844
2008 - 2010 Total Residential	**69,026**	**11,423**	**2,957**	**14,380**	**52,438**	**26,301**	**53,061**	**260**	**66,169**	**(739)**	**232**	**37,694**
2007 Total Residential Customers	***842,291***											
COMMERCIAL:												
New Construction	252	8,080	7,179	15,258	142,889	131,262	19,239	17,854	35,580	22,289	2,747	16,076
Retrofit	895	15,027	11,372	26,399	556,474	476,116	34,199	58,591	35,995	79,691	9,830	16,263
2008 - 2010 Total Commercial	**1,147**	**23,106**	**18,551**	**41,657**	**699,363**	**607,378**	**53,438**	**76,445**	**71,575**	**101,980**	**12,577**	**32,339**
2007 Total Commercial Customers	***89,994***											
SUBTOTALS:												
Energy Efficiency Subtotal	49,419	31,291	21,768	53,059	983,808	817,950	57,632	97,960	75,548	138,781	16,865	35,190
Program Subtotal	**70,174**	**34,530**	**21,508**	**56,037**	**751,801**	**633,679**	**106,499**	**76,705**	**137,744**	**101,240**	**12,809**	**70,033**
COMMUNICATIONS:												
Conservation Education & Outreach												
Joint Initiatives												
Trade Relations												
Innovative Technologies												
Conservation Potential Review												
Communications Total												
2008 - 2010 TOTAL	**70,174**	**56,365**	**21,508**	**77,872**	**751,801**	**633,679**	**106,499**	**76,705**	**137,744**	**101,240**	**12,809**	**70,033**

81.0 Reference: Exhibit B-1, Appendix 9, Habart Report, Admin Costs, p. 18

81.1 How were administration costs derived for each category shown in Exhibit 6.2?

Response:

Administration costs were derived based on the Companies' experience and best knowledge. The administration costs shown in Exhibit 6.2 are summations of the administration costs estimated for each program. Typically administration costs consist of:

- Program development costs
- Program management costs
- Evaluation
- External training
- Program Promotion and Marketing

82.0 Reference: Exhibit B-1, Appendix 9, Habart Report, RIM, p. 25

82.1 Please provide all available documentation supporting the statement that a RIM ratio of 0.6 is typical for DSM programs.

Response:

This comment in the Habart report is based on the consultant's direct experience with DSM programs, rather than a particular document. The consultant has many years experience in DSM and is recognized as an expert in the DSM field.

83.0 Reference: Exhibit B-1, Appendix 9, Habart Report, Marginal Costs, p. 2

83.1 Please provide the sources for each table.

Response:

The electricity marginal cost data was provided by Mr. John Duffy of BC Hydro in January 2007. Electricity rates came from the BC Hydro website.

The natural gas marginal cost data was developed by the Companies' Gas Supply group using the "SendOut" program, referred to in the response to BCUC IR 1.13.1. The rates came from the Companies' web site.

83.2 Are the values levelized, nominal or real and if so of what year?

Response:

The numbers are levelized and real in 2006 dollars for gas and 2007 dollars for electricity. The years are different because the work was done in early 2007. The impact from using different years is very small.

83.3 Please express Exhibits 2.2 and 2.3 in cents per KW.h assuming 100% conversion efficiency.

Response:

Please note that Exhibit 2.2: Marginal Costs - Electricity in the subject report has been labeled incorrectly. The cost numbers shown are $/MJ but have been labeled as $/GJ. The corrected table, with costs expressed as $/GJ to match the other tables, is included below.

Exhibit 2.2: Marginal Costs – Electricity (corrected)

Measure Life (Yrs)	10	15	20	25
Unit Price	$/GJ	$/GJ	$/GJ	$/GJ
Service Area				
Vancouver Island	$26.40	$26.40	$26.40	$26.40
Lower Mainland	$26.16	$26.16	$26.16	$26.16
Interior	$24.44	$24.44	$24.44	$24.44

The table below shows the converted values in cents per KWh assuming 100% conversion efficiency:

Measure Life (Yrs)	10	15	20	25
Unit Price	$/KWh	$/KWh	$/KWh	$/KWh
Service Area				
Vancouver Island	$0.0950	$0.095	$0.095	$0.0950
Lower Mainland	$0.0942	$0.0942	$0.0942	$0.0942
Interior	$0.0880	$0.0880	$0.0880	$0.0880

Please note that the revised Exhibit 2.3: Residential Rates -Customer Energy Prices includes commercial rates as well:

Exhibit 2.3: Residential Rates - Customer Energy Prices (expanded)

	Residential		Commercial	
Customer Energy Prices	Natural Gas $/MJ	Electricity $/MJ	Natural Gas $/MJ	Electricity $/MJ
Vancouver Island	$0.0137	$ 0.0176	$0.0118	$0.0155
Lower Mainland	$0.0113	$ 0.0176	$0.0107	$0.0155
Interior	$0.0113	$ 0.0176	$0.0108	$0.0155

The table below shows the converted values in cents per KWh assuming 100% conversion efficiency:

	Residential		Commercial	
Customer Energy Prices	Natural Gas $/KWh	Electricity $/KWh	Natural Gas $/KWh	Electricity $/KWh
Vancouver Island	$0.0493	$ 0.0634	$0.0425	$0.0558
Lower Mainland	$0.0493	$ 0.0634	$0.0425	$0.0558
Interior	$0.0493	$ 0.0634	$0.0425	$0.0558

84.0 Reference: Ontario Energy Board: DSM Handbook

84.1 Please confirm that the Ontario Energy Board has issued a DSM Handbook for Ontario natural gas local distribution companies. If so, please file the DSM Handbook.

Response:

Please refer to Attachment 84.1.

Please note that while this document was filed as part of Enbridge's Evidence in the Generic Proceeding before the OEB, it was superseded by the OEB's ruling EB-2006-0021 (which was included as Attachment 71.4 in the response to BCUC IR 1.71.4).

85.0 Reference: Summit Blue DSM Report

85.1 Please file the January 30, 2006 Summit Blue report entitled "Demand-Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Testing" prepared for CAMPUT.

Response:

Please refer to Attachment 85.1.

source: http://www.camput.org/documents/2006-02-13DSMFinalReport_001.pdf

Attachment 1.1

REFER TO ATTACHED SPREADSHEET

Attachment 1.3.1

Maximizing Societal Uptake of Energy Efficiency in the New Millennium: Time for Net-to-Gross to Get Out of the Way?

Rafael Friedmann, Pacific Gas & Electric Co., San Francisco, CA[1]

ABSTRACT

Humans are running out of time to reduce global warming gas emissions to avoid horrendous socio-political and environmental consequences. Reducing global warming effects may require an 80% decrease in greenhouse-gas emissions by the year 2050. This will require a sharp reduction in the use of fossil-fuels our modern civilization is based on. Widespread uptake of energy efficiency and conservation are the best options available to mitigate global climate change and provide time for developing more sustainable and renewable energy supply sources.

California's thirty-year promotion of energy efficiency provides valuable experience and an institutional and market infrastructure to broaden and deepen customer uptake of energy conservation and efficiency. California policymakers, entrepreneurs, and public show a heightened interest in energy efficiency.

To accelerate uptake of energy efficiency will require California to update evaluation policies and protocols for overseeing the almost one billion dollar per year publicly funded energy efficiency endeavor. Current evaluation is more focused on regulators need of attributing energy savings to specific programs and less so on optimizing interventions. Programs and evaluations are focusing mostly on energy efficient measures (EEMs) that get incentives.

This paper calls both evaluators and policy-makers overseeing energy efficiency portfolios to acknowledge the need for, and move to develop alternate evaluation policies, protocols and methods that will ensure publicly funded energy efficiency efforts are cost-effective, while also being supportive of non-traditional, more economical and deep market transforming interventions. These new evaluation policies and protocols should still ensure continued public oversight. The paper draws upon the California context to show how the Net-to-Gross ratio as currently applied inhibits new, market transforming energy efficiency interventions. Paper ends providing some initial thoughts on how to improve this situation.

Background

Society has long understood the crucial nature of energy to transform the natural world to get goods and services. This initially led to social support for the creation of an increasingly larger and complex energy supply system. With time, this evolution has been accompanied with an understanding that there are social costs that are not fully internalized by private markets and thus, suboptimal investments and developments occur in the energy sector.

This awareness of the suboptimal investment has led to a willingness to collect and use public funds to foster more socially optimal development of the energy sector. Energy efficiency programs funded with public funds is a good example. This public energy efficiency expense comes from a generalized understanding that the free market will not adopt higher efficiency on its own, nor will it

[1] Any opinions expressed explicitly or implicitly are those of the author and do not necessarily represent those of Pacific Gas and Electric Company.

internalize the socio-politic or economic benefits and costs of the variety of energy infrastructure it has developed.

Public good funds for energy efficiency seek to maximize public benefits at minimum cost. Figuring out how to best use these public funds is complicated by a myriad of factors including risks, uncertainty, investment in short versus longer term opportunities, and various intervention strategies that seek to overcome perceived barriers to energy efficiency adoption.

In California and elsewhere (NW, NE and mid-west USA), publicly funded energy efficiency has a long history. In California, it is over 30 years old and has encompassed a variety of intervention strategies and administrative structures. Since 1996, these interventions have been mostly administered and run by the four investor-owned-utilities (IOUs), using public funds collected in rates. Regulatory oversight by the California Public Utilities Commission (CPUC) has sought to ensure IOU expenses optimize the use of these public funds.

As part of the determination of optimal use of these public funds, evaluation protocols have been established and significant evaluation efforts have been done to measure savings from these program interventions (check www.calmac.org for evaluation studies, and TeckMarket Works 2004, 2006). To ensure that funds are used in the best fashion possible, evaluation has focused on determining both gross savings and net savings by energy-efficiency-measures (EEMs) and/or programs. Gross energy savings encompass the totality of energy saved by programs or portfolios. Net savings refer to the energy saved that can be attributed to the programs beyond what would have happened anyways or "baseline". Gross energy savings are adjusted using a "Net-to-Gross" (NTG) ratio which in principle should include both an upwards adjustment for savings obtained beyond the program (spillover) and a downward adjustment for savings which would have happened anyways absent the program (free-riders).

California's four main investor-owned-utilities are currently administering a three-year, 2.1 Billion dollar publicly funded energy efficiency effort, under oversight and policy guidance by the California Public Utilities Commission (CPUC). The goals for this three year effort are to save 5.1 TWh, 2.2 GW and 111 MM Therms of natural gas. These goals are part of a longer-term effort that sought to save during 2004-2012 about 23 TWh, 4.9 GW, and 444 MM Therms.

Given the most recent findings of the Intergovernmental Panel on Climate Change, there is an interest in trying to save even more energy. Indeed, California Assembly Bill 32 calls for California to return to 1990 greenhouse-gas emissions levels by the year 2020 and the Governor issued an executive order that seeks to cut emissions by 80% by 2050.

For California to reach these goals, will require doing more transformative energy efficiency by tapping and engaging markets both broader and deeper than those to date. Broader in the sense that everybody will need to engage in energy efficiency. Deeper in that everyone will need to do more than what they have done. We will need full adoption of energy efficient lighting, premium motors, systems focused energy efficiency rather than individual energy efficiency measures (EEMs), as well as capturing process engineering enhancements, integration with renewable energy technologies, etc.

The current energy efficiency evaluation protocols are too focused on attribution of savings; counting only direct program participants energy saving actions corrected for free ridership. This focus promotes portfolios based on EEMs that are easy to measure and verify; undervaluing resources spent on programs that have longer lead times and/or high spillover effects. Although the current evaluation focus addresses the CPUC's need to minimize crediting of free rider savings, it also affects and impacts addressing other important societal goals, such as maximizing net energy savings and GHG emissions reductions.

The remainder of this paper explores how California's evaluation protocols, especially with regards to NTG may be inadvertently constraining the variety of interventions and resulting in reduced energy savings yields. The paper begins by drawing on the diffusion of innovation concept (Rogers 1995) to describe barriers faced by customers seeking to adopt more energy efficient technology. The discussion focuses on how the NTG can vary at the various stages of technological market adoption. This provides insights that are then exemplified with three possible new interventions that could lead to large energy savings with minimal public goods funding but that are constrained by the current evaluation protocols from happening. The paper ends by discussing how these protocols make broader and deeper efforts riskier given the high savings targets/goals; reducing energy efficiency administrators and implementers shy away from broader and deeper, higher spillover, market transforming interventions.

Current context requires and allows for new, more cost-effective energy-efficiency adoption interventions

At least two major issues with past evolution of the energy sector have recently heightened interest in tapping all cost-effective energy efficiency options first: Global Warming and Resource Adequacy. Global warming requires a significant reduction of Greenhouse Gas (GHG) emissions (some say up to 80% by 2050) to avoid most of the expected socio-politico-environmental impacts identified in the most recent IPCC reports. The frailty of the current energy supply system has become especially obvious in the wake of the California electricity crisis of 2000-2001, the large northeastern blackout of 2005, and Hurricane Katrina. Energy efficiency showed its worth to society during and after the California crisis, saving up to 14% of peak demand and 7% of electricity use in 2001; saving California from experiencing ongoing blackouts that summer. Energy efficiency is also recognized as the most cost-effective option for reducing GHG emissions, with a variety of energy saving measures costing less than 3 ¢/kWh and 1.2 $/MMBtu (Prindle et al. 2007). Energy efficiency and conservation reduces pollution and also gives time to develop better supply alternatives, especially renewable energy technologies and services, where technical breakthroughs and more importantly, market maturity is needed for full cost-effective deployment.

The current context is very receptive to energy-efficiency. There is increased public and private interest in energy efficiency. Corporations are seeking to enhance profits and their image among consumers and shareholders. GE's Ecomagination division had revenues of 17 Billion dollars in 2006; Walmart has established a group focused on sustainability and advertised its intent to sell 100 million compact fluorescent lamps (CFLs) in 2007; Home Depot gave away 1 million of these CFLs this past Earth Day; IBM has announced a 1 Billion dollar program to help its client data centers become more energy efficiency; and among automakers, Toyota and Honda higher energy efficient cars have fueled these two companies profitability and increasing market share over there less energy-efficient-focused competitors. Venture and pension fund capital managers are also increasing its interest and "seeding" new renewable energy and energy efficient technologies. The media is not far behind, with stories about global warming, energy efficiency, and renewable energy technologies showing up regularly in both local and national print and video media, as well as long-term stalwarts of "free markets" like the Economist (Sep 2006). Customer interest in these topics and eagerness to "do what's right" is an at all time high. We've even seen customers banding together to stop TXU's Board's recent interest in building eight new coal-powered power plants.

Albeit the increased interest in energy efficiency, studies still show that not all cost-effective EE is being adopted by customers, nor is ongoing development of products and services fully obtainable from business-as-usual (D Goldstein 2007; Itron 2006). This is the reasoning behind the ongoing support of energy efficiency promotion with public funds.

The question that arises is whether these funds are being spent in the most cost-effective and energy saving manner. It is also important to examine how current evaluation protocols and policies may be impacting what energy efficiency interventions are undertaken. This paper only examines the impact of NTG's policies, leaving for another discussion other areas that require review and possible revamping.

Let us examine what precludes customers from adopting all cost-effective energy efficiency and how NTG and its determination are not straightforward. Current California protocols regarding application of NTG in essence, by only counting free-riders, ignore non-energy benefits, which typically are the key leverage points to get customers to adopt more efficient services or products. New evaluation protocols with a broader perspective on overall societal benefits could increase research on customers and market actors resource efficiency motivators; providing insights for the development of more cost-effective public interventions.

Barriers to Capturing Energy-Efficiency Opportunities

The objective of a publicly funded energy-efficiency portfolio is to accelerate adoption of efficient energy use practices and technologies across a variety of customers served. Theoretically, successful public interventions spur along the maturation of energy efficiency markets so that these reach a "tipping point" where public interventions are barely needed. To succeed, the portfolio offerings need to take into account this varied mix of customers and their needs, continuously adapting to the changing context in which they are implemented. This requires a thorough understanding of customers needs to enable program offerings to align and produce optimal results. In California, even with over a quarter century of publicly funded energy-efficiency promoting programs, the energy efficiency market is still immature. Yet a new, energy-efficiency enabling context is growing; providing new opportunities for public resources to leverage private efforts to hasten market maturity. The key therefore is to clarify where markets are, what are the key barriers to further development of the market, and how to best tap into public and private resources to hasten tipping points for energy efficiency adoptions when these are possible, while still supporting the needs of less mature market segments.

This section briefly discusses key barriers faced by customers seeking to adopt energy efficiency. It also discusses how the barriers and context customers face change as an innovative product disseminates into the marketplace. This sets the stage for understanding why the CPUC's focus on attribution and rules regarding application of NTG lead to suboptimal results.

Energy-efficiency proponents talk about at least four major barriers that preclude customers (and society) from adopting all the cost-effective energy efficiency options (see Friedmann & James 2005; Friedmann 2006). These barriers are:

- Awareness. Where customers lack information on the options available, and/or their benefits.
- Availability. Manufacturers do not make or market more efficient measures as they do not expect to have a market for these (usually invisible) enhancements to their products.
- Accessibility. Distributors and retailers may not stock or aggressively display the EEMs making it hard for customers to find the more efficient products and services they seek.
- Affordability. Usually, EEMs are more expensive than the widgets they seek to replace, partly because of better quality components, partly because of their less developed and less competitive markets, with higher transaction costs to get these to market.

In order to address the barriers mentioned above, a public energy efficiency portfolio will include research, development and demonstration (RD&D) efforts, information and education components, programs to persuade customers to adopt more energy efficiency widgets and practices, and codes and standards to enhance the efficiency of buildings and equipment. The resources devoted to each of these public interventions will be determined by the market maturity context in which the decisions are made. They will change over time, across customer segments, and draw upon appropriate programmatic and project-level interventions as needed.

The programmatic and project-level interventions used need to address in more efficient and cost appropriate methods the changing needs of the market they seek to influence. Thus, the energy efficiency portfolio will be ever changing, reaching into new areas for further energy-efficiency, and contracting in others, where savings have been tapped out, or where markets have evolved and do not require further public support to continue to evolve.

The evolution of the dissemination of an energy efficient technology can be theorized to follow an S-shaped curve with four major market stages (immature, maturing, mature, and new EE technology markets) as shown in Figure 1 (Rogers 1995). An effective portfolio will optimize the mix of offerings to best address the challenges being faced by each of these four stages of market evolution to align benefits with societal needs. The intent is to match portfolio offerings to market needs, and to do so at crucial leverage points. Some of these efforts will be upstream, midstream or downstream, and/or geographically defined.

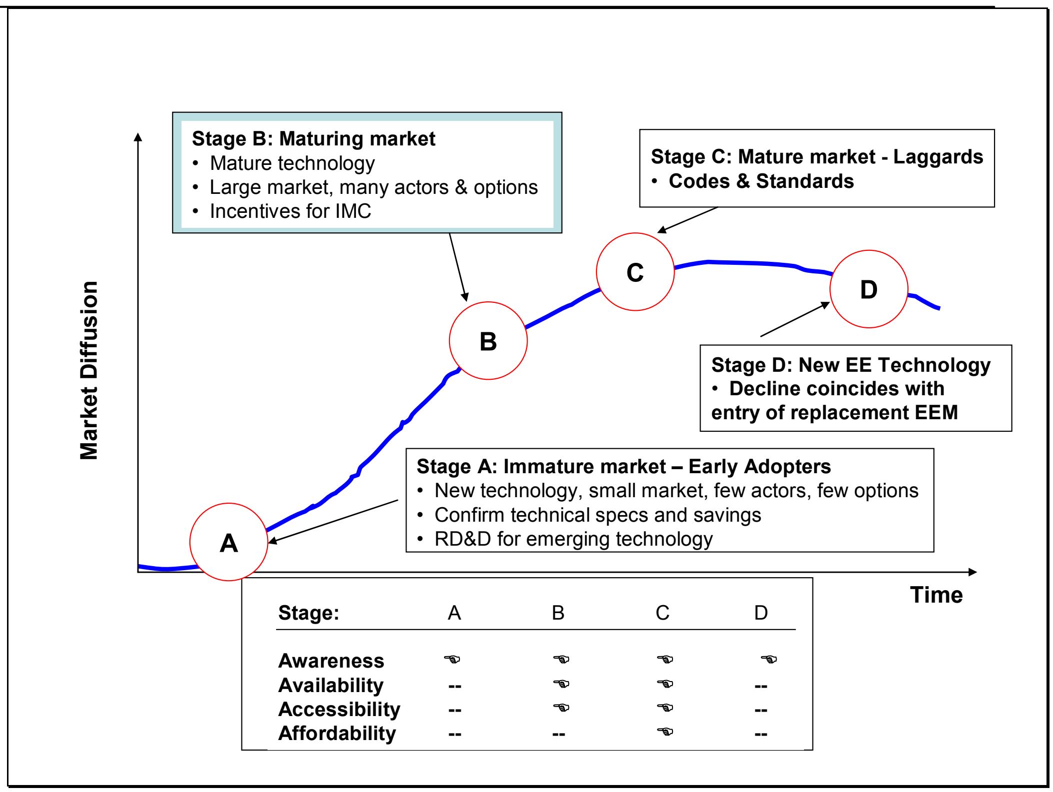


Figure 1. Market Evolution Curve for an EEM or EE Practice and Barriers Faced at Each Stage

There are important linkages among these four stages of market evolution. Stage A describes the early stages of a new technology or practice. Typical interventions for this stage focus on research, development and demonstration (RD&D). Decisions on what technologies or practices to include in the portfolio in Stage A depend on the remaining significant opportunities for energy savings. These depend in part on the previous maturation of other energy-efficiency measures addressing the more important customer energy end-uses. Indeed, Stage A and Stage D are interlinked, as the new technologies or practices being developed in Stage A begin to reduce the saturation in the market of the technology or practice that was previously being promoted by market interventions in Stages B, C and D. In Stage B, a technology or practice has become better known, is more available, accessible, yet still most likely, significantly more expensive than the less efficient technology or practice it seeks to supplant. Stage B is where most portfolio resources are typically spent currently, in the form of audits and incentive programs to help reduce the incremental costs of efficient measure's adoption. In Stage C, most of the customers have adopted the more efficient technology or practice, but some significant portion of the customers is unlikely to ever adopt it. In Stage C standards and codes are typically the intervention of choice to ensure that all customers adopt the more efficient technology given its significant societal benefits. By Stage C, the efficiency interventions administrator needs to be identifying and beginning to develop the next generation of technologies and/or practices to introduce (and start their own Stage A). This is reflected in Stage D, where the saturation of the current efficient technology is being impacted by the growing market presence of the next generation, even more efficient technology already in its own Stage A or perhaps even Stage B.

Eventually, as the private energy efficiency market grows and matures, one would hope that public support would center on Stages A and C, leaving private market actors to address most of Stage B. In this ideal theoretical construct, public funds would be used where most effective (namely where the private sector would not invest adequately due to the public good nature of that market), and be supplemented largely by private market actors positioning themselves to serve the maturing market customer in Stage B. Indeed, public resources would be used to guide and also provide credibility to private actors' best energy efficiency offerings in Stage B. This public-private market segmentation has only begun to occur in a few select situations, for example, with CFLs in homes and T-8 fluorescent bulbs in businesses. Even in these two cases, private market actors still look for various types of support from publicly funded programs. These public programs also are involved in coming up with the next generation of lighting products: LED and T-5 fluorescent lighting.

NTG and Maturing Markets for Energy Efficiency

Drawing from the diffusion of innovation for energy efficiency products and services curve, and the barriers inherent to each stage of market evolution, we examine here what factors affect the Net-to-Gross (NTG) ratio for any public interventions and the likely resulting value for NTG (see Table 1).

NTG at each stage of dissemination of innovation is different, as the key four barriers impact varies. NTG may be high in early adopter—because there is very low availability, accessibility for EEMs in Stage A. Although affordability and awareness also very low among the general population, they are actually high among the early adopter crowd. Thus, what the overall NTG—when defined as "what would have done without the program" depends on whether early adopters would have indeed been aware of the technology and been willing to spend more and seek it out to overcome the availability and accessibility barriers. Worse, should someone just focus on the early adopter participant customer's NTG it is likely the NTG would be quite low, and possibly lead to a decision to discontinue supporting the evolution of its' market. In this situation, spillover happens over time. Although the early adopters' NTG is low, through their actions and public support of market actors becoming engaged in the EEM, you are moving this technology to Stage B. Thus, just focusing on the early NTG, could lead to a decision to stop public support of the incipient EEM market, long before it is ready for uptake by the majority of customers and at least delaying capturing this technology's savings.

Table 1. NTG for Evolving Markets of EE Technologies

Market Stage	Participant Characteristics	Net-to-Gross Issues Of Participants
A. Immature	Early adopters. Embrace new technologies quickly	Awareness, affordability, accessibility, availability all low—imply high NTG; yet propensity to adopt is high among early adopters, possibly resulting in low NTG
B. Maturing	Majority of market. Require information, incentives, and other support to adopt efficient products	Relatively high NTG as these customers not "primed" to adopt new technologies and require information to be made aware, market support via upstream/midstream programs to enhance availability and accessibility, and incentives to improve affordability
C. Mature	Reticent/laggards. Lag at adopting new technologies or practices	Very high NTG as these customers very reticent to adopt EEMs. Indeed, C&S are used to force adoption, and even then, compliance with them can be very spotty
D. Decline	Back to early-adopters.	NTG indeterminate, depending on market barrier being faced for new, replacement EEM

In Stage B, all four barriers of awareness, availability, accessibility and affordability are being lowered. At this stage, the NTG for early adopters is low given the very high free-ridership; but for the mainstream customer, NTG is probably quite high initially and then, starts to decline as the market for the technology continues to mature.

In Stage C, all four barriers have been mostly overcome. The NTG is very low for both early adopters and mainstream customers, but very high for the late/never adopter. Adoption by the late adopters is obtained through mandatory energy efficient Codes and Standards. Yet compliance with the Codes or Standards remains a problem. NTG for these laggard customers is very high, but very low for all other customers.

We have seen that NTG is very dependent on the stage of market development for the energy efficient product being considered. Also, the rules on how NTG is applied can heavily influence the portfolio of energy saving strategies pursued. The market context within which we are seeking to enhance customer adoption of a particular energy efficiency product is also important. After 30 years of efforts and with the increased public and private interest in GHG, fossil fuel availability and socio-political implications of our dependence on them, it is becoming very hard to accurately estimate a NTG for a specific program intervention or EEM. Given the current context and energy savings goals under which California's energy efficiency programs are operating, it seems that a revision of the policies and their focus on NTG is needed. How these two aspects come together is discussed next.

NTG and Big, Bold Efficiency Interventions

In the search for new options to continue to garner energy savings and their accompanying socio-economic-environmental benefits to society, the question of how NTG (among other evaluation protocols) affects the possibility of carrying out effective new big and bold ventures comes up. We briefly describe three possible interventions being considered for the PG&E service territory and explore how current rules regarding NTG increase the risk of meeting savings goals making these interventions less interesting for the utility to pursue.

CFLs – Getting deeper and broader adoption by customers

About 31% of California homes have yet to install a single CFL. Of the remaining 69% of homes who have installed CFLs, only about 17% have installed 15 or more CFLs and can be assumed to have fully saturated their home lighting with CFLs (RLW 2005). Therefore, probably about half or more of the residential lighting is still using inefficient incandescent lights. According to the latest energy efficiency potential study (Itron et al. 2006), full saturation of CFLs would imply slightly over 100 million installed CFLs in PG&E serviced homes. The same study estimated at 53 million CFLs the maximum achievable saturation between 2004-2016. PG&E is seeking to accelerate adoption of CFLs via an upstream/midstream market program that offers about $2/CFL to manufacturers and distributors and retailers. This allows retailers to sell the CFLs for $1 each. Sales volumes have been increasing rapidly with up to 25 million expected in 2007, up from almost 7 million in 2006 and 4 million in 2005. Should this growth continue, PG&E homes will be close to CFL saturation in 2 to 3 years. The program has very low administrative costs by offering the incentives to manufacturers, distributors and retailers instead of customers. Yet this makes determining NTG very difficult, as participant contact information is unavailable. Instead success could be measured in terms of product availability, accessibility, affordability, and awareness. A survey of households (given that about 69% have CFLs) would still be hard pressed to get a reliable value for free-ridership given the multitude of energy efficiency messaging and promotions going on in the marketplace and that PG&E's incentive is almost invisible to the customer. Current evaluation protocols do not allow credit for any spillover, further reducing the per-protocols, official cost-effectiveness of the CFL upstream program. The program strategy is successful but can easily result in mistakenly high free ridership estimates. If the free ridership estimates come out too high, PG&E may decide to end this program (which also helps promote higher quality CFLs that have more of the characteristics customers want and that usually have led to rejection of CFLs in the past), before the CFL market is fully tapped out, leaving significant energy savings untapped.

Large Commercial Office Buildings

PG&E is currently offering a variety of products and services to large commercial office buildings. These include audits, retro-commissioning and commissioning, design-assistance, incentives for more efficient equipment, training on both, opportunities and enhanced operations and maintenance, etc. Customer outreach is mostly via PG&E Assigned Service Representatives (ASRs). The idea is that large office building managers can avail themselves of a variety of energy efficiency services to meet their needs through just one point-of-contact. Research is being conducted to allow for an even better focused program to meet this market segment needs. The idea is to characterize the large office buildings in PG&E territory by ownership and management set-up. PG&E will then reach out to these building owners and operators at the most appropriate levels of decision-making on energy-related investments, with appropriate messaging and utilizing the most appropriate PG&E staff level. This will imply establishing long-term relationships at various levels of both PG&E and the large office building manager or owner that will enhance uptake by the customers. Rather than focusing most of the effort on incentives, it is quite likely that efforts will be required at non-rebated aspects of the business decision. Tracking and determining the ultimate influence on energy savings of this variety of interventions among a variety of decision-makers (e.g., across the engineering or capital investments leadership within these organizations) over a long period of time, will be very difficult, and figuring out a free-ridership ratio even more difficult. How would one apportion such a free-ridership if say 8 of 9 decision makers were totally keen on adopting the technology (i.e., free riders) yet the 9^{th} and final decision maker (or even the first one on the decision-tree) only agreed to the enhancement thanks to the intervention of PG&E? How will a NTG based only on participant free-ridership underestimate the energy savings from spillover, within the organization and variety of decision-makers involved and their impact on their peer groups and over time? How interested will PG&E be in pursuing this business model if there is a high level of risk on what savings will be ultimately apportioned to its efforts, partly because of current protocols governing NTG and the difficulty of estimating it?

Data Centers—Brave New World

PG&E estimates data center load growth at between 400 and 500 MW. A variety of hardware and software options are now available that can cost-effectively reduce the energy used by these data centers by one-half or more. This requires implementation of a variety of measures in a synergistic fashion, including the promotion of standards and metrics for data center equipment, and promotion of improved data center designs and operation schemes. Outreach and promotion from a credible source such as PG&E (who does not sell the equipment) is crucial. As PG&E only sells energy to these data centers, its efforts to promote a variety of products and services being offered by a variety of firms (including IBM, HP, Sun, Intel, VMWare, etc.) are providing critical credence to the claims of these various vendors as well as optimal integration of the services and products offered by them. PG&E also sponsored a data center design charrette in 2005 that helped develop ideas on how to improve energy efficiency in these facilities. Yet, how will the savings from these efforts be apportioned among the entities involved? Given that affordability is not a key issue for this market, whereas awareness and credibility are, how will free-ridership be measured? Given the quick uptake and high turnover of personnel typical of this marketplace, with the expectation that about half of it will have adopted for example virtualization (whereby they can get rid of about 70-80% of the servers and cooling needs of a data center by increasing the load from 10% to 70% in each server), will evaluations be able to gather reliable free ridership (or spillover) data before the market is basically transformed? Given the large savings being obtained with minimal public resources, this effort appears to be very cost-effective and something to try to emulate in other markets. Under current policies it is unclear what savings will be attributed to PG&E's efforts.

These three examples show issues around using NTG (especially based solely on free-ridership), and how focusing on attribution of savings is not only near impossible for these big and bold strategies, but worse, makes these very risky endeavors for PG&E to pursue.

California Needs New Evaluation Protocols for Energy Savings Attribution

Given the rapidly changing, increasingly embracing energy efficiency context we live in California, it is imperative to develop new evaluation methods, policies and protocols that will help guide and ensure optimal use of public energy efficiency resources. These new policies and protocols should foster leveraging much larger private resources with carefully crafted public interventions.

Current California protocols and CPUC rulings need to be updated to increase the focus on maximizing social benefits accruing from public resources, to balance these goals with the current one that focuses on attempting to attribute savings to specific public efforts; and take advantage of a societal context where there is a large opportunity for saving energy by leveraging market actors resources. There is an increasing level of activity from private market actors that is tapping into energy efficiency regardless of the presence of publicly funded, utility administered efforts. Customers are more interested in adopting energy efficiency than ever before as they try to do their part to solve a variety of issues they care about (Climate Change, USA's "addiction to oil", Iraq war, etc).

Utilities need to meet goals that are set at levels that are hard to achieve under current rules governing what counts or does not if they are to get shareholder incentives for their energy efficiency efforts. The CPUC requires evaluations to estimate NTG, but only considering free riders, with no credit for spillover savings. Given current market conditions, it is impossible to estimate a reliable free-rider-based NTG and/or spillover. Furthermore, the reticence to accept spillover leads to increased resources being assigned to programs where the savings not only are "counted" but also, "attributable" and help programs meet their large energy savings goals. Current policies lead implementers to avoid programs that may have large spillover effects; in essence spending the resources in less cost-effective efforts. And to add insult to injury, yesterday's spillover (that you never accounted) turns into today's baseline. In the long run this leads to underestimation of energy savings and cost-effectiveness.

The inordinate focus on attribution also takes away resources that could be used to better understand the markets we are trying to influence, thus detracting from the quality and depth of the information we use in designing and running publicly funded energy saving interventions. Evaluation activities are thus done in an institutional framework that determines the scope of the activities and analyses undertaken. The majority of energy efficiency programs are done with public monies overseen by a public entity. This institutional framework leads to evaluations that cater to the needs of ensuring public oversight, but not necessarily clearly identifying the needs of customers, or the programs that attempt to get customers to adopt energy efficiency. As these are the major evaluative efforts, they also affect the evaluation community framing the scope of enquiry and methods. In my view, the current framework may be giving us a distorted view-as it does not encompass other issues that may be crucial at really finding out what works, as efficiency markets evolve.

As the CPUC gets ready to define energy efficiency goals for 2009-2011, there is an increased awareness of the changing context, the increased difficulty for determining NTG, and the need to review the rules and evaluation protocols under which the IOUs administer the energy efficiency public endeavors.

Of late, there is a growing concern among evaluation practitioners about the capability of estimating accurately NTG and attribution of savings to specific programs given the current context, and/or using these to design program offerings (see recent conference proceedings of AESP 2007, IEPEC 2006, and Barnes 2007; Chappell et al. 2005; R Friedmann 2005, 2006; Saxonis 2007). Market effects indicators appear to be the preferred choice at this juncture (Chappell et al. 2005). Much more work is needed here to develop new indicators and then protocols aligned with them to foster the ongoing evolution of energy efficiency markets and energy savings by customers.

Conclusions

Paper has shown that the current context in California allows for new energy efficiency intervention strategies. Given the private market's interest in selling or adopting energy efficiency to increase profits and show good corporate citizenship and customer's increased interest to "do what's right", publicly funded efforts can change their "mainstream" efforts to interventions that optimize leveraging of private market actor efforts. Publicly funded efforts will still need to deal with creating new options for early adopters as well as addressing "laggard" customers via Codes and Standards. It is with the mainstream customer that publicly funded efforts can now let the relatively mature California energy efficiency market take a bigger role and even the lead, and intervene with public funds to "oil" this private markets' machinery.

Current evaluation policies and protocols make difficult such a change in public energy-efficiency interventions. They insist on calculating free-ridership and not allowing for savings from non-incented energy efficiency improvements. Changing current policies to allow for counting spillover from participants and non-participants needs to be addressed.

But both spillover and free-ridership are becoming much harder to determine as the context becomes one that embraces energy efficiency (for a variety of reasons that have little to do with saving energy). Therefore, new evaluation metrics, methods, policies and protocols need to be developed to better understand customer adoption decision-making, identification of key leverage points in the markets for energy efficient products and services, so that publicly funded interventions can continue to focus their efforts in the most cost-effective and socially beneficial manners.

References

H. Barnes. 2007. "Market-Effects Momentum: Are We Giving Market Effects Their Full Due?" *In Proceedings of the 2007 IEPEC,* Oregon, WI: International Energy Program Evaluation Conference. Forthcoming.

California Public Utility Commission. 2004. "Energy Saving Goals for Program Year 2006 and Beyond." Decision 04-09-060. San Francisco, Calif.: Public Utilities Commission of the State of California.

Chappell, C., D. Mahone, L. Megdal, and K. Keating. 2005. "White Paper on Methods for Estimating Net-to-Gross Ratio for Non-Residential New Construction." Southern California Edison.

Friedmann, R., and K. James. 2005. "Optimal Design, Implementation, and Evaluation of an Energy Eficiency Portfolio." *In Proceedings of the IEPEC 2005 Conference,* 911-919. Madison, WI.: International Energy Program Evaluation Conference.

Friedmann, R. 2006. "Time to Sweep the Dust From Under the Rug?" *In Proceedings of the 2006 ACEEE Summer Study.* 8:76-87. Washington D.C.: American Council for an Energy-Efficient Economy.

Goldstein, D. 2007. *Saving Energy, Saving Jobs.* San Francisco, CA.: Bay Tree Publishing.

Itron, Kema, RLW Analytics, and AEC. 2006. *California Energy Efficiency Potential Study.* Sam Francisco, CA.: Pacific Gas and Electric Company.

Prindle, B. M. Eldridge, M. Eckhardt, and A. Frederick. 2007. *The Twin Pillars of Sustainable Energy: Synergies Between Energy Efficiency and Renewable Energy Technology and Policy.* Washington D.C.: American Council for an Energy-Efficient Economy.

RLW Analytics. 2005. *California Statewide Residential Lighting and Appliance Efficiency Saturation Study.* San Diego, CA: San Diego Gas & Electric Company.

Rogers, Everett (1995). *Diffusion of Innovations.* New York: The Free Press.

W. Saxonis. 2007. "Free Ridership and Spillover: A Regulatory Dilemma." *In Proceedings of the 2007 IEPEC,* Oregon, WI: International Energy Program Evaluation Conference. Forthcoming.

TecMarket Works. 2004. *The California Evaluation Framework.* Prepared for Southern California Edison Company. Oregon, WI: TecMarket Works.

TecMarket Works. 2006. California Energy Efficiency Evaluation Protocols: *Technical, Methodological, and Reporting Requirements for Evaluation professionals*. Oregon, WI: TecMarket Works.

Attachment 37.1

Natural Resources Canada   Ressources naturelles Canada

BACKGROUND REPORT FOR THE PREPARATION OF A CANADIAN STANDARD ON THERMAL ENERGY METERS FOR HYDRONIC HEATING/COOLING SYSTEMS

Prepared for:

Natural Resources Canada
CANMET Energy Technology Centre – Varennes

By:
Tom Onno, Gagest Inc

Revised
April 2005

CITATION

Onno, T., Background Report for the Preparation of a Canadian Standard on Thermal Energy Meters for Hydronic Heating/Cooling Systems, report # CETC-Varennes 2005-055 (TR) CANMET Energy Technology Centre – Varennes, Natural Resources Canada, April 2005, 13 p.

DISCLAIMER

This report is distributed for informational purposes and does not necessarily reflect the views of the Government of Canada nor constitute an endorsement of any commercial product or person. Neither Canada nor its ministers, officers, employees or agents makes any warranty in respect to this report or assumes any liability arising out of this report.

ACKNOWLEDGEMENT

The preparation of this report was funded by the Government of Canada's Climate Change Action Plan 2003, through the Technology and Innovation Programme.

TABLE OF CONTENTS

BACKGROUND REPORT FOR THE PREPARATION OF A CANADIAN STANDARD ON THERMAL ENERGY METERS FOR HYDRONIC HEATING/COOLING SYSTEMS

1 Summary

The district heating/cooling industry is new in Canada but is rapidly expanding. Currently, no Canadian standard exists for meters used to record the accumulated thermal energy supplied by a district heating (DH) utility to a customer. As a result, the application of metering for revenue billing has been problematic due to non-certified equipment and lack of standardized installations. Errors in recorded energy values and lack of reliability have occurred leading to decreased confidence in the viability of metering. Two heat metering installations in remote communities have been abandoned because of obvious inconsistencies in the data.

New thermal energy meters have improved performance and the old international documents have become obsolete. Recent European standards and international recommendations have been developed. It is an appropriate time to evaluate Canadian requirements for standards and compare these to work that has been done in other countries.

With fully certified metering, the concept of "user pays" will become widely accepted in space heating, cooling and consumption of domestic hot water. Based on the European experience this will lead to reduced consumption and slower depletion of fossil fuels. Some Canadian applications of thermal energy metering include high rise condominium buildings as well as the potential for sub-metering in apartment buildings.

Sommaire

L'industrie canadienne de la distribution urbaine de chaleur et de froid est encore jeune mais croît rapidement. Présentement, aucune norme canadienne ne couvre les compteurs utilisés pour le mesurage de l'énergie thermique fournie par un système urbain à un usager donné. Ainsi des installations non standardisées de même que l'usage de compteurs non certifiés dans un contexte de facturation est problématique. La confiance dans les systèmes de mesures actuelles s'en trouve d'autant diminuée que des erreurs ont été décelées dans le mesurage d'énergie de certains systèmes ; en particulier deux systèmes de chauffage urbain dans des communautés éloignées ont été abandonnés dû à des incohérences flagrantes dans les données énergétiques.

De nouveaux compteurs d'énergie thermiques démontrent maintenant une performance accrue, rendant du même coup certains documents internationaux obsolètes. Aussi, de nouvelles normes européennes et recommandations internationales ont ainsi été développées. À ce moment, il s'avère donc approprié d'évaluer les exigences canadiennes et de les comparer avec celles développées par d'autres pays.

Le mesurage par des installations certifiées rendra le concept d'« utilisateur-payeur » de plus en plus acceptable dans les domaines de chauffage et de climatisation d'espace ainsi que pour la consommation d'eau chaude domestique. Suivant l'expérience européenne, cela mènera également à une consommation réduite et une certaine préservation des ressources d'énergie fossile. Les applications canadiennes du mesurage d'énergie thermique incluent les bâtiments en hauteur du type condominium de même que le potentiel pour le mesurage à l'échelle des utilisateurs dans les édifices à logements.

2 Background

2.1 Evolution of district heating systems in Canada

Until the 1980's most of the district heating in Canada consisted of steam distribution systems. Usually these were on government building complexes, including military bases, or university campuses. Due to the common ownership of the buildings, there was no need for accurate metering for revenue billing purposes.

In the meantime, northern Europe evolved rapidly to hot-water based district heating systems. Cities such as Helsinki presently obtain over 80% of their heat from large, multi-fuel power plants which often combine electric power generation (cogeneration) with waste heat extraction for district heating.

There is currently a rapid expansion of new, hydronic district heating/cooling systems in Canada. At least nine systems of the megawatt size exist and a number of others are in the planning stages. Six of these have cogeneration plants. Others utilize a renewable biomass fuel, reducing greenhouse gasses and creating local employment.

Hydronic heating/cooling systems lend themselves to accurate metering. Promotion of economical, low-grade energy can be marketed to a variety of customers, if there is an acceptance of accurate metering methods.

2.2 Description of hydronic thermal energy meters

Thermal energy meters measure the supply and return temperatures at the load and the volume flow rate of the liquid. In certified measurement systems water is generally used, with additives for water quality control.

The thermal power being transported by the liquid is proportional to the product of temperature difference and the flow rate. A microprocessor computes these quantities and applies corrections to compensate for water density and specific heat changes with temperature and for non-linearities in sensors. The values of instantaneous power are accumulated to memory registers that can only be reset by pass-codes. Most thermal energy meters have options to transmit data via remote readout equipment.

2.2.1 Potential for errors due to low temperature difference

Often when a load is connected to a DH system it is difficult to accurately predict the peak loads and the statistics on load variations. This is especially true when aging buildings are connected to the system. In some older systems loads are connected to a nominally constant flow loop. This results in temperature difference proportional to power being extracted from the fluid. The problem is particularly acute in cooling systems, some of which have been observed to operate at temperature differences below 2 ºC for a large part of the time. The international standard for thermal energy meters specifies 3 ºC as the minimum operating temperature difference.

2.2.2 Potential for errors due to low liquid flow rate

Depending on the design, in a hydronic heating system there can be significant variations in flow levels and it is important to have a large "turn-down ratio" in the flow sensor. Some flow sensors can operate to below 3% of peak flow before the relative error begins to exceed specification. Other sensors have much lower turn-down capability. An example is the orifice plate, which has a differential pressure output proportional to the square of flow rate. This approach is typically limited to a turn-down ratio of about five.

2.2.3 Difficulty of correcting errors in accumulated energy

As a result of the multiplication of the two variables of flow and temperature difference the thermal energy meter is prone to error if either of the quantities is low while a high value of thermal power is being transported. Consequently, it is impossible to fully correct for errors that are identified after an extended period of operation. For example, a common source of error in differential temperature measurements is an offset error. Even if this error were to stay nominally constant, when the magnitude of differential temperature varies down to low values the relative error will vary in a nonlinear manner. The effects of offset error can only be corrected if the time series values of both flow and temperature difference are available for analysis.

2.3 Need for standards in the Canadian district energy industry

It is estimated that slightly over 1,000 thermal energy meters are currently used in Canada for revenue billing. At present there is no Canadian standard to define the accuracy and operational characteristics of thermal energy meters. Often there is a simple contractual agreement between the energy supplier and consumer to pay whatever the energy meter registers. Since there is usually no prior agreement between the parties involved regarding a definition of accuracy, the lack of standards has the potential for legal problems if significant errors are found after an extended period of operation.

A number of problems have been observed with older thermal metering installations in Canada due to the lack of a standard, including:

2.3.1 Lack of water density and specific heat correction. This can cause over one percent added error, depending on the operating temperature levels.

2.3.2 Use of temperature sensors designed to be mounted on the surface of pipes instead of in thermal wells or directly immersed in the flow. Large errors occur due to loose mounting and insufficient insulation.

2.3.3 Potential for errors due to use of semiconductor temperature sensors at low levels of temperature difference. Some meters use thermistors and other semiconductor devices instead of the platinum RTDs (resistance temperature detectors) which are matched to 0.05 ºC in certified meters. The new international standards state the "Maximum Permissible Error (MPE)" must be less than 0.1 ºC even after years of operation.

2.3.4 Lack of points to attach seals on critical parts of the installation, making it easy to tamper with the accuracy.

2.3.5 Data transfer to external systems is not standardized.

2.3.6 Errors due to use of non-standard hardware and one-off software incorporated in building monitoring/control systems. In a large system a cumulative error was identified when compared to a newly installed heat meter. This was due to rounding errors in the building monitoring software, as a result of resetting some accumulators each midnight.

2.3.7 Lack of confidence by sellers and buyers of heat energy due to lack of standards. There have been cases where potential users of thermal energy metering have lost interest when they found there is no standard. Concern over potential liability was stated as one of the reasons for not applying this technology.

2.4 Impact of certified meters on energy conservation

As indicated in 2.3.7, the lack of a standard has been a barrier to the acceptance of heat metering in Canada and impacts negatively on Canada's energy conservation. Other countries have found a reduction of 20 to 30% in energy consumption for heating and cooling and 30 to 50% reduction in consumption of hot water[i] once energy charges were implemented[1].

2.5 Recommended technical features in modern thermal energy meters

Modern thermal energy meters avoid the problems discussed in 2.3. In order to make a meter fully functional for both revenue billing and diagnostic purposes a number of features are necessary:

[i] (marketing document from SVM Sweden, based on more than 25 reports by independent energy authorities, encompassing six northern European countries)

- Accumulated values should include water volume as well as the standard energy quantity. The water volume, together with energy, allows calculation of “flow-weighted average temperature difference”, which will indicate if water flow has been excessive. A number of instances have been seen where the supply to the domestic hot water heat exchanger goes into a high flow condition due to improper control and is not detected for extended periods.
- Instantaneous values of flow and temperatures as well as error indicators.
- The ability to switch the unit into fast response outputs for testing and calibration.

3 Proposed terms of reference

3.1 Standards for both heating and cooling systems

Both heating and cooling will be included in the standard, as many new Canadian buildings are now air conditioned from a central source. Both four-pipe and two-pipe systems are used. At least one European manufacturer of thermal energy meters has recently begun production of a unit designed for two pipe heating/cooling systems. This meter computes two values of energy based on both positive and negative temperature difference. Energy is accumulated into separate registers, allowing different tariffs to be applied for heating and cooling.

3.2 Steam systems

It is assumed that no standard will be developed at this time on steam systems. Steam energy flow is difficult to measure to a high accuracy and the use of steam systems is in decline.

3.3 Use of semiconductor sensors for temperature measurements

In principle, any temperature sensor that meets the accuracy specification of the standard should be considered acceptable. However, the question of long-term stability in diverse environments is more complex and difficult to specify. The current practice in certified thermal energy meters is to use platinum temperature sensors, which have a proven track record for extended periods of operation. As background there is need to obtain expert input regarding certification test procedures that may involve accelerated life-cycle tests specific to potential modes of accuracy deterioration in semiconductor sensors.

3.4 Provincial boiler pressure codes

Due to historical considerations carried over from steam systems, flowmeters fall under the boiler code. Since the boiler pressure code is a provincial jurisdiction, consideration may need to be given to the certification procedure for flowmeters in the provinces. Possibly the most stringent provincial boiler codes will need to be identified and used as the overall standard.

Flowmeters that meet a provincial pressure code are assigned a CRN number. There is some uncertainty regarding the implications of this pressure code. When flowmeters are used directly on the high temperature/high pressure part of a district heating system the need for certification under the boiler code is important. Since larger district heating distribution systems are often designed to operate up to 120 ºC or higher there is serious danger of steam generation if a line is broken.

A different situation exists in a local heat distribution system inside a building either isolated from a district heating system by a heat exchanger, or supplied by a local boiler. This will typically operate at a lower pressure and at a temperature below the boiling point[ii]. The building distribution system will be protected by over-temperature and over-pressure relief valves in case there is a loss of temperature control. This is similar to the protection on a domestic hot water tank for residential hot water. In spite of this protection, the code states that plumbing components used above 65 ºC and 16 bar pressure must have a CRN certification number. The meters being manufactured in Europe are certified at these levels.

CRN certification is a complex procedure. It requires:

- Submission of the detailed production drawings for a full design review (to evaluate wall thickness, etc)
- Materials evaluation to compare to materials that have been previously certified under CRN– tensile tests, over-pressure testing
- Quality control during manufacturing – ISO 9001

As a result most European meters are not certified under the Canadian provincial pressure codes.

There is a need to establish if the certification procedures can be linked to the European certifications.

3.5 Communication protocols for remote readout of energy meter data

Consideration needs to be given to three commonly used standards:

- M-bus - allows multiple meters to be addressed from a master controller, with requests to transmit data.
- Lonworks - this system can be set up for repetitive transmission of data, allowing the data to be used for control applications.
- RS 232 - allows direct connection to a modem for automatic dialup from a computer.

[ii] An example is sub-metering in an apartment building.

3.6 Sub-metering of domestic hot water to estimate energy consumption

In modern, well-insulated residential buildings the consumption of domestic hot water (DHW) is often a significant part of the energy load. In some applications, such as apartment buildings, low-cost, simplified methods of sub-metering for DHW consumption are used. This is often done by using water volume only and assuming constant delivered hot water temperature. Currently there appear to be no standards for this methodology, but some consideration could be given to future addition of this capability. There would need to be standards for these flowmeters and the software used to compute the DHW energy equivalent to the water volume. Accuracy will be improved by proposed changes to the National Building Code that will limit the delivered DHW temperature of new installations to 49 ºC by use of a fixed tempering valve. As a minimum any new standard for DHW metering should state that the flowmeter must be located after a tempering valve.

4 Procedures to define standards

Steps in the procedure:

- Background work by NRCan, to supply information to the Standards Committee
- Nomination of committee members to draft the technical standard
- Nomination of advisory members to supply comments on policy questions
- Development of a draft standard.
- Comments on the draft standard by the district heating industry, solar energy industry, and companies involved in high-rise sub-metering
- Preliminary evaluation of the specification of thermal energy meters being sold in Canada to evaluate compliance to the standard
- Discussions with Industry Canada to obtain information on procedures that will be implemented to evaluate meters for compliance to the standard

4.1 Background work by NRCan, including review of currently applicable recommendations and standards

4.1.1 Organisation Internationale de Métrologie Légale (OIML)[2]

OIML is the main international agency dealing with metrology and Canada is a member of this organization. The main reference for accuracy specifications could be OIML R 75, which addresses thermal energy meters. This document is defined as an "International Recommendation". They are "model regulations that establish the metrological characteristics required of certain measuring instruments and which specify methods and equipment for checking their conformity; the OIML Member States shall implement these Recommendations to the greatest possible extent". As stated in its introduction, the OIML R 75 was developed on the basis of 1997 European Standard EN 1434[3], which is discussed next in 4.1.2.

OIML R 75 is available in English and French and can be down-loaded free at:
http://www.oiml.org/publications

This recommendation will be in at least three parts:

OIML R 75-1	Heat meters	Part 1: General requirements (17 pages). Based on EN 1434 part 1
OIML R 75-2	Heat meters	Part 2: Type approval tests and initial verification tests (20 pages). Based on EN 1434 parts 4,5
OIML R 75-3	Heat meters	Part 3: Test report format (to be published in at a later stage, superceding the 1988 edition)

The OIML R 75 recommendation currently refers only to heat meters and it can not be applied directly to cooling systems, by simply reversing the definition of supply and return temperature measurements. The test procedures for temperature sensors specifies a minimum temperature of 5 ºC and the lowest temperature for the flow sensor is specified as not less than 10 ºC. Some cooling systems operate at temperatures below 5 ºC. The environmental conditions specify the relative humidity as less than 93%. This could be a problem, since the flowmeter in a cooling application could have condensing conditions on its surface.

Since OIML R 75 is a new document and is still under development, it does not encompass the full scope of the requirements that were addressed in more detail by the European standard EN 1434 (1997). In particular, the important area of communication protocols is not covered although these are mentioned in the references.

A possible approach would be to use OIML R 75 as the starting point, with modifications and additions as required to meet the needs of the Canadian industry.

An example of a potential variance for Canada is the two standards for platinum alloys used in the temperature sensors. The European standard has a factor of 0.385% per ºC, while the North American standard is 0.3915% per ºC. Both are equally accurate, but the European thermal metering standard only defines the linearization equation for the 0.385 factor. If it is decided to permit both standards in Canada, as a minimum it should be mandatory to define the temperature sensor factor on the meter faceplate.

4.1.2 Comité Européen de Normalisation (CEN) or European Committee for Standardization

CEN developed the European Standard, EN 1434 (1997) and the EN 1434 specifies requirements in detail. Until such time as OIML R 75 is as complete as EN 1434, the latter standard will need to be used as reference material for the Canadian standard.

In 2002 EN 1434 was amended (A1) to include cooling applications.

EN 1434 (1997) is currently in six parts:

Part 1: Heat Meters - General Requirements (24 pages)

Part 2: Heat Meters - Constructional Requirements (29 pages)

Part 3: Heat Meters - Data Exchange and Interfaces (53 pages)

Part 4: Heat Meters - Pattern Approval Tests (22 pages)

Part 5: Heat Meters - Initial Verification Tests (7 pages)

Part 6: Heat Meters - Installations, Commissioning, Operational Monitoring and Maintenance (13 pages)

4.1.3 European Union Measurement Instrument Directive (Doc.9681/4/03 REV 4)

This directive was accepted early in 2004. The section of the document referencing heat meters is a seven page summary listing the main accuracy specifications of OIML R 75 and EN 1434.

4.1.4 American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE)

A preliminary search of the ASHRAE standards[4] has identified a test procedure for thermal energy meters:

> Standard 125-1992 (RA 2000)—Method of Testing Thermal Energy Meters for Liquid Streams in HVAC Systems (ANSI approved)
>
> “The purpose of this standard is to provide a method of testing factory-assembled thermal energy meters used to measure the thermal energy added to or extracted from a liquid stream supplying an HVAC system”.

4.2 Technical support

4.2.1 National Research Council – Institute for National Measurement Standards (INMS)

To address the concerns regarding the long-term stability of thermistors and the guaranteed accuracy with which their exponential characteristic can be mathematically linearized, contact will be made with NRC - INMS. They are responsible for national standards on temperature measurements and have a number of experts in this field. Their input will also be requested on other semiconductor temperature sensors.

4.2.2 International Energy Agency (IEA) [5]

Previous work by IEA examined accuracy and reliability considerations in detail. Testing was done on the newest technologies being used in thermal energy meters, and recommendations made regarding standards. This work was done in the period 1988-1990[6] [7] [8] [9] [10] and is partly out of date. Some of the information on test procedures and field testing is still relevant.

Recent IEA work[11] has emphasized usage of the communication features of modern thermal energy meters to supply information for demand side management. Since district heating systems are even more prone to overload at peak conditions in comparison to electric utilities, there is the potential to make significant improvements in the overall efficiency of the energy supply system by controlling peak demand.

5 Input from district heating industry

Contact will be made with Industry Canada, manufacturers of heat meters, retailers, installers and calibration facilities.

6 Evaluation of new standards by comparison to current equipment

After a draft standard is issued an evaluation of specifications will be done of heat metering equipment currently or potentially available in Canada. The objective will be to establish whether most of the equipment from serious manufacturers can fit into a specific class within the standard.

7 Certification process for thermal energy meters

After a standard has been issued a process will need to be set up to certify whether a given meter can be sold in Canada with a compliance certificate. If the Canadian standard has a well established relationship with reference to the OIML R 75 and EN 1434 documents this could be a fairly simple process.

8 Recommendations for installation procedures

Due to the relative complexity of heat meters and the lack of installation experience in Canada, it may be necessary to define basic installation considerations that could be overlooked in the manufacturer's installation instructions. For example, the EN 1434 includes specifications for maximum wire lengths for two-conductor cable of various wire gauges that are permissible for use with platinum temperature sensors.

References

[1] Cut Energy Costs the SVM Way. A. B. Svensk Värmemätning. Sweden. p 13.

[2] Organisation Internationale de Métrologie Légale, 11 rue Turgot - 75009 Paris - France.

[3] Comité Européen de Normalisation (CEN). Central Secretariat: rue de Stassart 36, B-1050-Brussels.

[4] Website: http://resourcecenter.ashrae.org/store/ashrae/newstore.cgi?itemid=6893&view=item&page

[5] IEA Secretariat, Mr. Hans Nilsson, 9 Rue de la Federation, F-75139 Paris, Cedex 15, France.

[6] IEA District Heating. Small Heat Meters. National Energy Administration. Sweden. 1988:R12.

[7] IEA District Heating Project. Heat Meters: Information project on R & D activities in the IEA countries. SINTEF Report. Norway. 1989. STF15 A89011.

[8] IEA District Heating Project. Heat Meters: Field test equipment (Background study). SINTEF Report. Norway. 1989. STF15 F89029.

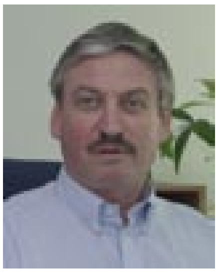
[9] IEA District Heating Project. Small Heat Meters: Laboratory & Field Tests. SINTEF Report. Norway. 1989. STF15 A89032.

[10] IEA District Heating. Heat Meters: Report of Research Activities - Annex II. SINTEF Report. Novem. Norway. 1990: R10.

[11] IEA District Heating and Cooling, Annex VI. Optimised District Heating Systems Using Remote Heat Meter Communication and Control. Danish Technological Institute. Novem. The Netherlands. 2003. Report 2002:S7.

The installation of meters leads to permanent changes in consumer behaviour

Mr. Lars Gullev, Managing Director, VEKS



Mr. Michael Poulsen, Operation Manager, Albertslund Fjernvarme

A reduction in consumption of up to 30% has been registered after the transition from joint to individual metering. The reduction in consumption occurs rapidly – usually one to two years after the transition to individual metering – and the reduction is maintained in the subsequent years. Consumers must be provided with detailed information well ahead of the transition to individual metering if a rapid reduction in consumption is to be achieved. The introduction of metering is a prerequisite if district heating consumers - be they members of building associations or people in dense/low dwellings - are to be motivated to invest in energy-saving activities. This article is an updated version of the article "The installation of meters leads to changes in consumer behaviour" from News from DBDH 3/1999.

Background

The expansion of the municipality of Albertslund, located to the west of Copenhagen, took off at the beginning of the sixties. Prior to 1963, the area contained only the villages of Herstedøster, Herstedvester and Vridsløselille, as well as a number of farms and nurseries. As the municipality grew, the first steps towards the building of Albertslund Fjernvarme (the local district heating plant), were taken in 1963. The introduction of a district heating system guaranteed a source of cheap heat for the consumers who were connected to the network. In addition, it offered the possibility of exploiting the surplus heat from the municipal waste incineration plant which became operational in 1969. The explosive expansion of the municipality meant that by 1974 the capacity of the heating plant had increased to 149 MW. The share of the district heating production which did not originate from the waste incineration plant was based on fuel oil.

Sandfilter for polishing of the treated circulation water from the RO equipment. In the same pipe is the pH measuring equipment placed. The treated circulation water of the system adjusted to a pH level between 9,8-10,1.

Albertslund's highest point and landmark, the plant's two 86 meter high funnels are decorated by the local artist Mr. Billy Suhr.

Albertslund Fjernvarme was set up as a municipally owned company, unlike the majority of the district heating companies in Denmark, both then and now.

As fuel oil was so inexpensive at the end of the sixties and the beginning of the seventies, it did not make sense economy wise to install meters in the homes of consumers. The district heating charge applied at the time was very simple: consumption was calculated on the basis of the floor area (in square meters) of the individual building in relation to the total floor area supplied by Albertslund Fjernvarme.

In the beginning of the seventies, 92% of the Danish energy consumption was based on imported oil. Therefore it came as a shock to the country when Denmark, along with the rest of Western Europe, fell prey to the serious oil supply crisis that dominated the winter of 1973/74. One immediate consequence of the supply crisis was a threefold increase of the price of oil over the course of just six months.

In both 1974 and 1977 the municipality of Albertslund issued reports which showed that potential savings in the consumption of district heating were not thought to warrant the additional costs associated with the introduction of a meter-based charging system, regardless of the dramatic increases of the price of imported oil. The reports concluded that the introduction of other energy-saving measures would be more profitable in economic terms than the installation of meters. The municipality therefore prepared an ”Energy Saving Plan” in which all aspects of buildings supplied with district heating were examined in detail. A list of possible energy-saving measures was prepared, out of which the following may be mentioned:

- Sealing of gaps.
- Additional insulation provided by secondary glazing.
- Reinsulation of outer walls and/or roof.
- Insulation of external cellar walls to approx. 1 meter below the ground.
- Outdoor temperature-dependent control with night/weekend reduction.
- Adjustment of heating systems.
- Regulation of room temperature by means of radiator thermostats.
- Regulation of room temperature by means of room thermostats that start and stop the heating system.
- Increased recirculation/periodic operation of ventilation systems.
- Replacement of hot-water tanks.

Legally, however, Albertslund Fjernvarme was unable to force individual district heating consumers to implement the suggested energy-saving measures. There was insufficient motivation to invest in the energy-saving measures, since the existing settlement charge was not based on individual consumption in individual homes.

The introduction of meters was therefore necessary if the energy-saving measures were to be put into place. The district heating consumption could be measured using the branch pipe that leads to the individual building, or using an area reading taken from the branch pipes that supply a group of buildings such as a housing estate. The delimitation of an area reading was defined as follows: ”The area delimited by a branch pipe with one decision-maker for the implementation of energy-saving measures”.

In areas with building associations and owner-occupied flats, the readings would be taken from the main branch pipes (joint settlement). For other consumers, the readings would be taken where the branch pipes were connected to the individual properties (individual settlement). In cases of joint settlement, it was up to the individual building association to distribute the costs amongst the individual homes. Building associations usually chose to distribute consumption according to the floor area of the individual home in relation to the total floor area of the apartment block. This ”charge” was simple to administer, but it did not motivate individual consumers to reduce their heat consumption.
Following the installation of a total of 2,400 meters in 1981, Albertslund Fjernvarme changed its system on January 1, 1982, when a two-part charge was introduced:

- A fixed charge designed to ensure that the fixed costs of the heating plant were covered regardless of the district heating consumption. The charge was set as a fixed sum/m^2 of connected heated area.
- A variable charge designed to cover the variable costs of the heating plant. The charge reflected the consumer’s registered consumption.

Circulation pumps from VEKS, to the Albertslund 50 MW heat exchanger

Experience
The following sections focuses on the heat consumption of a number of representative dwellings during the period 1991–2005, in order to establish whether the location of the meter (i.e. the use of joint or individual metering) affects the behaviour of consumers and thereby the heat consumption.

The following use of the term “individual metering” refers to the measurement of heat consumption in individual households, using either energy meters or evaporation meters located on radiators. The behaviour of consumers in individual households will thereby be directly reflected by the individual readings and, consequently, the amount paid by the consumer. The term “joint metering” applies in all other cases.

The figures given here cover consumption resulting from heating and the production of hot domestic water. The figures for consumers have also been adjusted according to the numbers of degree days to reflect the yearly mean consumption, thereby enabling direct comparisons to be drawn.

The buildings are characterised by having either joint metering for the entire period, or by having changed from joint metering to individual metering over the course of the period. The study focuses on three types of buildings:

- Dense/low owner-occupied dwellings (terraced houses)
- Dense/low rented dwellings (terraced houses)
- Multi-storey buildings

Dense/low owner-occupied dwellings (Figure 1)
In this case, the buildings were Platanparken (160 houses) and Elmehusene (106 houses). They are identical in terms of their construction time, size and ownership. This enables any potential differences between the settlement method and consumption to be seen clearly. The only difference between the two developments is that Platanparken had individual metering for the entire period. Elmehusene had joint metering until July 1,1995, when individual metering was introduced. In both cases, heat consumption is based on

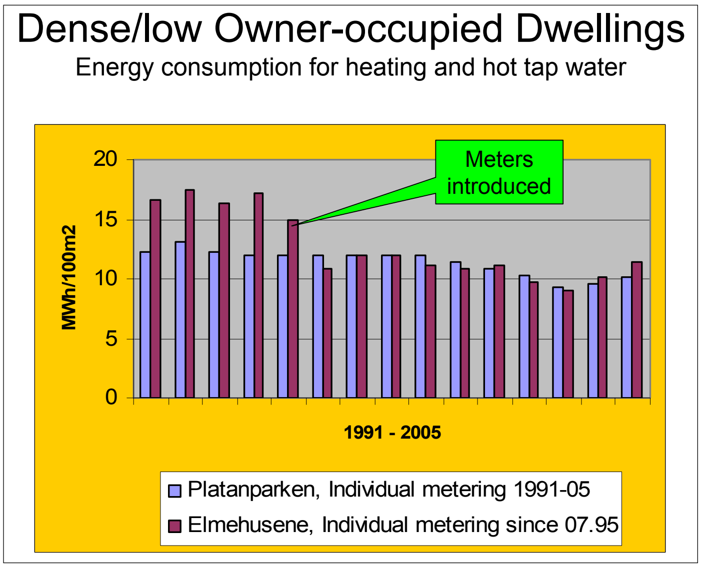


Figure 1: Dense/lov owner-occupied dwellings

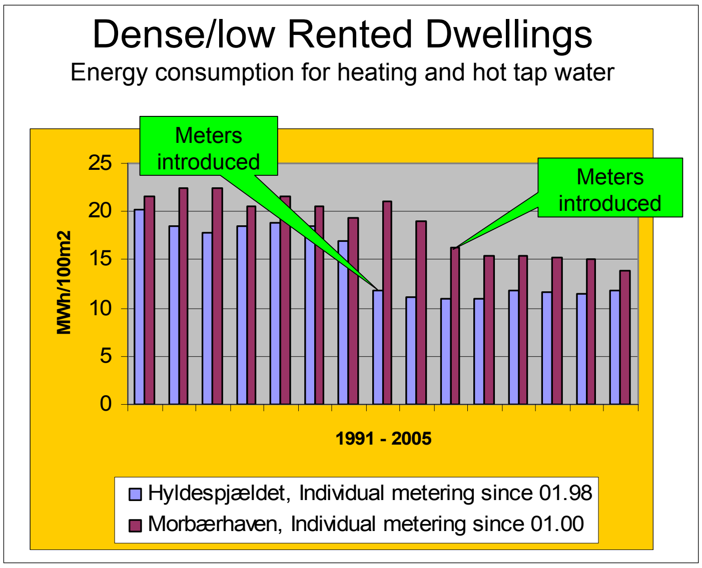


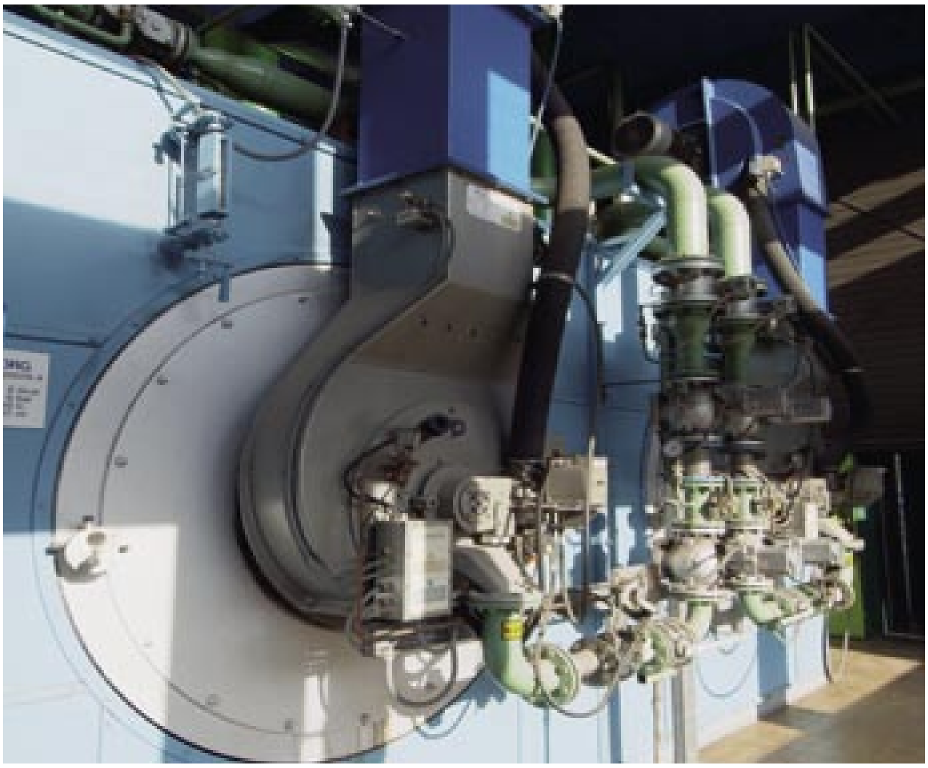
Figure 2: Dense/lov rented dwellings

the readings taken from the main meter. The results show clearly that the consumption figures for Elmehusene (joint metering) were significantly higher (up to 44%) than those associated with Platanparken during the period before 1995. Following the introduction of individual metering at Elmehusene, the consumption was significantly reduced and is now on par with the consumption at Platanparken. Since 1991, the consumption at Platanparken has been reduced by 17%. At Elmehusene, however, it was reduced by 31%. The introduction of individual metering has therefore resulted in a significant reduction in consumption.

Dense/low rented dwellings (Figure 2)
The buildings in this case were Hyldespjældet (390 houses) and Morbærhaven (1,063 houses). Hyldespjældet had joint metering until the end of 1997, when the houses switched to individual metering. On the other hand, the buildings at Morbærhaven had joint metering for the entire period.

The results clearly show that the consumption at Hyldespjældet fell by 31% in comparison with the consumption in 1997, following the introduction of individual metering in 1998. Over the entire period from 1991, consumption has been reduced by more than 42%. The consumption at Morbærhaven has been reduced by around 28% since the introduction of meters in 2000. The fact that it was possible to reduce consumption at Hyldespjældet by more than 42% and at Morbærhaven by more than 36% since 1991 must be seen in light of the fact that the consumption in 1991 was relatively high. This created a good basis for a reduction.

Combined oil and gas boilers; if needed the boilers can be converted to using pulverized coal as well



Multi-storey dwellings (Figure 3)
The buildings in this case were Topperne (383 houses), Albertslund Nord (224 houses) and Banehegnet (184 houses). Topperne had joint metering until the end of 1992 when individual metering was introduced. Both Albertslund Nord and Banehegnet had joint metering until the end of 1995 when individual metering was introduced.

Once again, the results speak for themselves. Consumption is reduced following the transition to individual metering, with the reduction appearing at the latest two post-transition years. The reduction was highest in the case of Topperne, with a registered drop in consumption of 21% from 1992 to 1994. A drop of 15–17% from 1995 to 1997 was registered in the case of the other two developments. All three developments noted a further reduction up till 2005.

Summary
A reduction in consumption of up to 30% can be registered following the transition from joint to individual metering. The reduction becomes apparent relatively quickly, usually one or two years after the transition to individual metering, and it is maintained in the subsequent years. It is also possible to conclude that houses which have identical consumption figures in connection with joint metering show sizeable variations of up to 20% following the transition to individual metering. It is therefore impossible to calculate the exact expected reduction in consumption following the transition to individual metering. However, a drop of at least 15–17% is a realistic result.

The speed with which the reduction in consumption is registered following the transi-

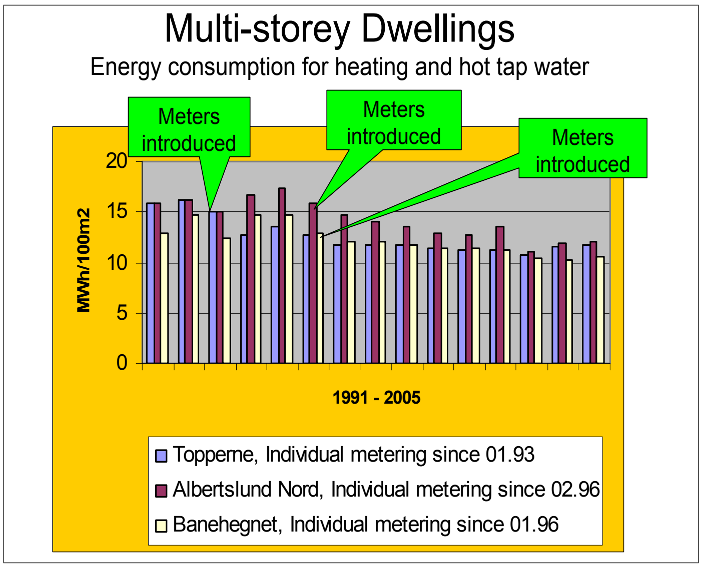


Figure 3: Multi-storey dwellings

Part of the deairraitor system, the pump and the heat exchanger

tion to individual metering depends on a number of factors, including the quality of the information given to consumers before the transition to individual metering.

When a general requirement to reduce energy consumption exists, and if district heating consumers - be they housing associations or members of other consumer categories - are to be motivated to invest in energy-saving activities, it is absolutely vital that metering is introduced. Only if the consumers themselves feel that they benefit from the advantages achieved by investing in energy-saving measures, will they choose to make such investments.

For further information please contact:

Albertslund Varmeværk

Att.: Mr. Michael Poulsen
Postadresse: Vognporten 9,
DK - 2620 Albertslund
Phone: +45 4364 8692
Fax: +45 4364 3888
E-mail: michael.poulsen@albertslund.dk

VEKS
Att. Mr. Lars Gullev
Roskildevej 175
DK - 2620 Albertslund
Denmark
Phone: +45 4366 0366
Fax: +45 4366 0369
E-mail: lg@veks.dk

Attachment 40.2

	Program Name	Gross Annual Savings (GJ)	Measure Life (Years)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
TGI	New Constr Fireplace	8.3	15	4,150	16,600	41,500	41,500	41,500	41,500	41,500	41,500	41,500	41,500	41,500	41,500	41,500	41,500	41,500	37,350	24,900	
TGI	New Constr E* Clotheswasher	3.4	14	1,700	5,100	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200	8,500	5,100		
TGI	New Constr E* Dishwasher	2.5	13	5,000	12,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	17,500	10,000			
TGI	New Constr Range	-9.3	18	-27,900	-65,100	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600	-111,600
TGI	New Constr Dryer	-4.3	18	-3,870	-9,890	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060	-18,060
TGI	Retrofit FP	8.3	15	16,600	37,350	62,250	62,250	62,250	62,250	62,250	62,250	62,250	62,250	62,250	62,250	62,250	62,250	62,250	45,650	24,900	
TGI	Retrofit Furnace	13.8	18	55,200	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400	110,400
TGI	Retrofit E* Dishwasher	2.5	13	5,000	12,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	22,500	17,500	10,000			
TGI	Retrofit E* Clotheswasher	3.4	14	6,800	17,000	30,600	30,600	30,600	30,600	30,600	30,600	30,600	30,600	30,600	30,600	30,600	23,800	13,600			
TGI	30% EE Building Design - Large	1504	25	1,504	4,512	12,032	12,032	12,032	12,032	12,032	12,032	12,032	12,032	12,032	12,032	12,032	12,032	12,032	12,032	12,032	12,032
TGI	30% EE Building Design - Small	550	25	1,100	3,850	8,250	8,250	8,250	8,250	8,250	8,250	8,250	8,250	8,250	8,250	8,250	8,250	8,250	8,250	8,250	8,250
TGI	60% EE Building Design	3007	25	3,007	9,021	18,042	18,042	18,042	18,042	18,042	18,042	18,042	18,042	18,042	18,042	18,042	18,042	18,042	18,042	18,042	18,042
TGI	High Performance Glazing	640	25	640	1,920	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840
TGI	Near Condensing Boilers	685	25	5,480	10,960	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125
TGI	Condensing Boilers	1114	25	5,570	16,710	33,420	33,420	33,420	33,420	33,420	33,420	33,420	33,420	33,420	33,420	33,420	33,420	33,420	33,420	33,420	33,420
TGI	Inst. DHW	73.2	15	1,098	2,928	5,490	5,490	5,490	5,490	5,490	5,490	5,490	5,490	5,490	5,490	5,490	5,490	5,490	4,392	2,562	
TGI	Cond DHW Boilers	1238	25	6,190	18,570	37,140	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952
TGI	Cond DHW Heaters	107.8	10	862	2,156	3,881	3,881	3,881	3,881	3,881	3,881	3,881	3,881	3,018	1,725						
TGI	Drainwater Heat Recovery	443.1	20	2,216	6,647	13,293	13,293	13,293	13,293	13,293	13,293	13,293	13,293	13,293	13,293	13,293	13,293	13,293	13,293	13,293	13,293
TGI	Retrofit Near Condensing Boilers	975	25	73,125	156,000	248,625	248,625	248,625	248,625	248,625	248,625	248,625	248,625	248,625	248,625	248,625	248,625	248,625	248,625	248,625	248,625
TGI	Retrofit Condensing Boilers	1533	25	7,665	19,929	35,259	35,259	35,259	35,259	35,259	35,259	35,259	35,259	35,259	35,259	35,259	35,259	35,259	35,259	35,259	35,259
TGI	Retrofit Building Recommissioning	975	10	14,625	34,125	68,250	68,250	68,250	68,250	68,250	68,250	68,250	68,250	53,625	34,125						
TGI	Retrofit Next Generation BAS	487	10	1,948	4,870	8,766	8,766	8,766	8,766	8,766	8,766	8,766	8,766	6,818	3,896						
TGI	Retrofit Demand Control Ventilation - Large	487	15	9,740	29,220	58,440	58,440	58,440	58,440	58,440	58,440	58,440	58,440	58,440	58,440	58,440	58,440	58,440	48,700	29,220	
TGI	Retrofit Demand Control Ventilation - Medium	197.6	15	3,952	11,856	23,712	23,712	23,712	23,712	23,712	23,712	23,712	23,712	23,712	23,712	23,712	23,712	23,712	19,760	11,856	
TGI	Retrofit HE Rooftop Units	176.4	20	706	1,764	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175
TGI	Retrofit Inst. DHW	73.2	15	1,464	4,392	8,784	8,784	8,784	8,784	8,784	8,784	8,784	8,784	8,784	8,784	8,784	8,784	8,784	7,320	4,392	
TGI	Retrofit Cond DHW Boilers	1238	25	18,570	55,710	111,420	111,420	111,420	111,420	111,420	111,420	111,420	111,420	111,420	111,420	111,420	111,420	111,420	111,420	111,420	111,420
TGI	Retrofit Cond DHW Heaters	107.8	10	2,156	6,468	12,936	12,936	12,936	12,936	12,936	12,936	12,936	12,936	10,780	6,468						
TGVI	New Water Heating	-18.8	10.0	-6,317	-15,717	-28,877	-28,877	-28,877	-28,877	-28,877	-28,877	-28,877	-28,877	-22,560	-13,160						
TGVI	New Constr Fireplace	8.3	15	2,324	6,964	13,927	13,927	13,927	13,927	13,927	13,927	13,927	13,927	13,927	13,927	13,927	13,927	13,927	11,603	6,964	
TGVI	New Constr E* Clotheswasher	2.8	14	119	357	832	832	832	832	832	832	832	832	832	832	832	832	713	475		
TGVI	New Constr E* Dishwasher	2.1	13	416	1,040	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,080	1,664	1,040			
TGVI	New Constr Range	-7.6	18	-296	-882	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052	-2,052
TGVI	New Constr Dryer	-3.8	18	-290	-869	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027	-2,027
TGVI	Retrofit Furnace Load Build	-53.2	18	-31,920	-63,840	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760	-95,760
TGVI	Retrofit Furnace DSM	10.8	18	324	972	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
TGVI	Retrofit FP Load Build	-15.8	15	-2,370	-6,810	-13,130	-13,130	-13,130	-13,130	-13,130	-13,130	-13,130	-13,130	-13,130	-13,130	-13,130	-13,130	-13,130	-10,760	-6,320	
TGVI	Retrofit FP DSM	8.3	15	166	498	996	996	996	996	996	996	996	996	996	996	996	996	996	830	498	
TGVI	Retrofit E* Dishwasher	2.1	13	368	998	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	2,048	1,680	1,050			
TGVI	Retrofit E* Clotheswasher	2.9	14	328	980	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,633	980			
TGVI	Retrofit Dryer	-3.8	13	-855	-2,565	-5,130	-5,130	-5,130	-5,130	-5,130	-5,130	-5,130	-5,130	-5,130	-5,130	-5,130	-4,275	-2,565			
TGVI	Retrofit Range Load Build	-7.8	18	-1,755	-5,265	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530	-10,530
TGVI	30% EE Building Design - Large	1504	25	0	0	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504
TGVI	30% EE Building Design - Small	550	25	0	0	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
TGVI	60% EE Building Design	3007	25	0	0	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007
TGVI	High Performance Glazing	640	25	0	0	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
TGVI	Near Condensing Boilers	640	25	640	1,280	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,920
TGVI	Condensing Boilers	1114	25	1,114	2,228	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342
TGVI	Inst. DHW	73.2	15	146	366	659	659	659	659	659	659	659	659	659	659	659	659	659	512	293	
TGVI	Cond DHW Boilers	1238	25	1,238	2,476	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952	4,952
TGVI	Cond DHW Heaters	107.8	10	108	216	431	431	431	431	431	431	431	431	323	216						
TGVI	Drainwater Heat Recovery	443.1	20	443	886	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772
TGVI	Retrofit Near Condensing Boilers	975	25	7,800	16,575	26,325	26,325	26,325	26,325	26,325	26,325	26,325	26,325	26,325	26,325	26,325	26,325	26,325	26,325	26,325	26,325
TGVI	Retrofit Condensing Boilers	1533	25	1,533	6,132	12,264	12,264	12,264	12,264	12,264	12,264	12,264	12,264	12,264	12,264	12,264	12,264	12,264	12,264	12,264	12,264
TGVI	Retrofit Building Recommissioning	975	10	1,950	3,900	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	5,850	3,900						
TGVI	Retrofit Next Generation BAS	487	10	0	487	974	974	974	974	974	974	974	974	974	487						
TGVI	Retrofit HE Rooftop Units	121.8	20	0	122	244	244	244	244	244	244	244	244	244	244	244	244	244	244	244	244
TGVI	Retrofit Inst. DHW	73.2	15	146	439	878	878	878	878	878	878	878	878	878	878	878	878	878	732	439	
TGVI	Retrofit Cond DHW Boilers	1238	25	2,476	6,190	12,380	12,380	12,380	12,380	12,380	12,380	12,380	12,380	12,380	12,380	12,380	12,380	12,380	12,380	12,380	12,380
TGVI	Retrofit Cond DHW Heaters	107.8	10	216	647	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,078	647						

Note: Negative numbers represent an increase in load

Summary Table	
Total Measure Life (Yrs)	1100
Average Measure Life (Yrs)	18.03
Weighted Average Measure Life (Yrs)	22.61
Total Savings Over Measure Life (GJ)	17,086,678

	Program Name	Gross Annual Savings (GJ)	Measure Life (Years)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Program Savings over Measure Life
TGI	**New Constr Fireplace**	8.3	15											**622,500**
TGI	**New Constr E* Clotheswasher**	3.4	14											**142,800**
TGI	**New Constr E* Dishwasher**	2.5	13											**292,500**
TGI	**New Constr Range**	-9.3	18	-83,700	-46,500									**-2,008,800**
TGI	**New Constr Dryer**	-4.3	18	-14,190	-8,170									**-325,080**
TGI	**Retrofit FP**	8.3	15											**933,750**
TGI	**Retrofit Furnace**	13.8	18	55,200										**1,987,200**
TGI	**Retrofit E* Dishwasher**	2.5	13											**292,500**
TGI	**Retrofit E* Clotheswasher**	3.4	14											**397,800**
TGI	**30% EE Building Design - Large**	1504	25	12,032	12,032	12,032	12,032	12,032	12,032	12,032	10,528	7,520		**300,800**
TGI	**30% EE Building Design - Small**	550	25	8,250	8,250	8,250	8,250	8,250	8,250	8,250	7,150	4,400		**206,250**
TGI	**60% EE Building Design**	3007	25	18,042	18,042	18,042	18,042	18,042	18,042	18,042	15,035	9,021		**451,050**
TGI	**High Performance Glazing**	640	25	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,200	1,920		**96,000**
TGI	**Near Condensing Boilers**	685	25	17,125	17,125	17,125	17,125	17,125	17,125	17,125	10,960	5,480		**426,755**
TGI	**Condensing Boilers**	1114	25	33,420	33,420	33,420	33,420	33,420	33,420	33,420	27,850	16,710		**835,500**
TGI	**Inst. DHW**	73.2	15											**82,350**
TGI	**Cond DHW Boilers**	1238	25	4,952	4,952	4,952	4,952	4,952	4,952	4,952	2,476	1,238		**174,558**
TGI	**Cond DHW Heaters**	107.8	10											**38,808**
TGI	**Drainwater Heat Recovery**	443.1	20	13,293	13,293	11,078	6,647							**265,860**
TGI	**Retrofit Near Condensing Boilers**	975	25	248,625	248,625	248,625	248,625	248,625	248,625	248,625	175,500	92,625		**6,215,625**
TGI	**Retrofit Condensing Boilers**	1533	25	35,259	35,259	35,259	35,259	35,259	35,259	35,259	42,924	15,330		**896,805**
TGI	**Retrofit Building Recommissioning**	975	10											**682,500**
TGI	**Retrofit Next Generation BAS**	487	10											**87,660**
TGI	**Retrofit Demand Control Ventilation - Large**	487	15											**876,600**
TGI	**Retrofit Demand Control Ventilation - Medium**	197.6	15											**355,680**
TGI	**Retrofit HE Rooftop Units**	176.4	20	3,175	3,175	2,470	1,411							**63,504**
TGI	**Retrofit Inst. DHW**	73.2	15											**131,760**
TGI	**Retrofit Cond DHW Boilers**	1238	25	111,420	111,420	111,420	111,420	111,420	111,420	111,420	92,850	55,710		**2,785,500**
TGI	**Retrofit Cond DHW Heaters**	107.8	10											**129,360**
TGVI	**New Water Heating**	-18.8	10.0											**-288,768**
TGVI	**New Constr Fireplace**	8.3	15											**208,911**
TGVI	**New Constr E* Clotheswasher**	2.8	14											**11,648**
TGVI	**New Constr E* Dishwasher**	2.1	13											**27,040**
TGVI	**New Constr Range**	-7.6	18	-1,756	-1,170									**-36,936**
TGVI	**New Constr Dryer**	-3.8	18	-1,737	-1,158									**-36,480**
TGVI	**Retrofit Furnace Load Build**	-53.2	18	-63,840	-31,920									**-1,723,680**
TGVI	**Retrofit Furnace DSM**	10.8	18	1,620	972									**34,992**
TGVI	**Retrofit FP Load Build**	-15.8	15											**-196,947**
TGVI	**Retrofit FP DSM**	8.3	15											**14,940**
TGVI	**Retrofit E* Dishwasher**	2.1	13											**26,618**
TGVI	**Retrofit E* Clotheswasher**	2.9	14											**25,485**
TGVI	**Retrofit Dryer**	-3.8	13											**-66,690**
TGVI	**Retrofit Range Load Build**	-7.8	18	-8,775	-5,265									**-189,540**
TGVI	**30% EE Building Design - Large**	1504	25	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504	1,504		**37,600**
TGVI	**30% EE Building Design - Small**	550	25	550	550	550	550	550	550	550	550	550		**13,750**
TGVI	**60% EE Building Design**	3007	25	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007	3,007		**75,175**
TGVI	**High Performance Glazing**	640	25	640	640	640	640	640	640	640	640	640		**16,000**
TGVI	**Near Condensing Boilers**	640	25	1,920	1,920	1,920	1,920	1,920	1,920	1,920	1,280	640		**48,000**
TGVI	**Condensing Boilers**	1114	25	3,342	3,342	3,342	3,342	3,342	3,342	3,342	2,228	1,114		**83,550**
TGVI	**Inst. DHW**	73.2	15											**9,882**
TGVI	**Cond DHW Boilers**	1238	25	4,952	4,952	4,952	4,952	4,952	4,952	4,952	2,476	1,238		**121,324**
TGVI	**Cond DHW Heaters**	107.8	10											**4,312**
TGVI	**Drainwater Heat Recovery**	443.1	20	1,772	1,772	1,329	886							**35,448**
TGVI	**Retrofit Near Condensing Boilers**	975	25	26,325	26,325	26,325	26,325	26,325	26,325	26,325	18,525	9,750		**658,125**
TGVI	**Retrofit Condensing Boilers**	1533	25	12,264	12,264	12,264	12,264	12,264	12,264	12,264	10,731	6,132		**306,600**
TGVI	**Retrofit Building Recommissioning**	975	10											**78,000**
TGVI	**Retrofit Next Generation BAS**	487	10											**9,740**
TGVI	**Retrofit HE Rooftop Units**	121.8	20	244	244	244	122							**4,872**
TGVI	**Retrofit Inst. DHW**	73.2	15											**13,176**
TGVI	**Retrofit Cond DHW Boilers**	1238	25	12,380	12,380	12,380	12,380	12,380	12,380	12,380	9,904	6,190		**309,500**
TGVI	**Retrofit Cond DHW Heaters**	107.8	10											**12,936**

Note: Negative numbers represent an increase in load

Summary Table	
Total Measure Life (Yrs)	1100
Average Measure Life (Yrs)	18.03
Weighted Average Measure Life (Yrs)	22.61
Total Savings Over Measure Life (GJ)	17,086,678

Attachment 41.1

REFER TO ATTACHED SPREADSHEET

Attachment 46.4

Free Ridership and Spillover: A Regulatory Dilemma

*William P. Saxonis, New York State Department of Public Service, Albany, NY**

ABSTRACT

Techniques for the measurement of free ridership have improved in recent years, but estimates still frequently suffer from a fairly high degree of uncertainty. The measurement of spillover has been even less certain. Can regulators rely on this data to help guide decisions on program design, budgets, program performance and energy policy? Currently there is a wide variance across the nation regarding how regulators view and utilize free rider and spillover data. There have been many studies addressing free ridership and spillover but relatively few have examined these factors in tandem, including exploring their combined impact on a program's benefit to cost ratio (B/C), and as tools for better understanding the marketplace, especially consumer behavior.

This paper critically examines recent free rider and spillover results from energy efficiency programs administered by the New York State Energy Research and Development Authority (NYSERDA). Based on recent NYSERDA program results, the free rider rates for commercial and industrial (C&I) programs ranged from 10-67 percent and the spillover rates ranged from 19 to 168 percent. For residential programs, the statistics are only somewhat less dramatic with free ridership ranging from 2-28 percent and spillover from 5 to 48 percent. Impacts of this magnitude can have a major influence on calculating net energy impacts and ultimately a program's B/C ratio. These results strongly suggest that a better understanding of free ridership and spillover is critical for the regulatory, evaluation and program design communities. This paper places free rider and spillover measurement in a historical context, compares the NYSERDA results to results from other states and concludes with challenging, but practical, recommendations.

Introduction

Free Ridership, Spillover and Net to Gross Defined

There is general consensus that a free rider is a program participant that would have, at least to some degree, taken the same action promoted by the program even if there were no program. From a benefit cost perspective, program benefits attributable to free riders represent a cost, but not corresponding program benefits.

Spillover reflects benefits attributable to an energy program, but without requiring program incentives and not directly credited to the program. There are two major categories of spillover- participant and non-participant. Participant spillover is attributable to program participants that implement measures that were not incentivized by the program. For example, a business owner impressed by the cost savings at the company's manufacturing plant resulting from participation in a lighting efficiency program decides to install energy efficient lighting in a branch sales office without assistance from the program.

Non-participant spillover is associated with actions influenced by an energy program, but not linked with direct program participation. This type of spillover can occur in a number of ways including through a conscious awareness of the program (e.g., advertising) or because the program induces

* Any opinion expressed explicitly or implicitly are those of the author and do not necessarily represent those of the New York State Department of Public Service or the members of the Public Service Commission.

changes in the marketplace (e.g., stocking practices). For example, a homebuilder decides not to participate in a program designed to encourage sales of high-energy efficient homes, but increases the energy efficiency of their product offerings to remain competitive with builders participating in the program.

Despite the challenges associated with accurately measuring free riders and spillover, also sometimes called attribution analysis, they are essential components in calculating a program's net-to-gross (NTG) ratio. This ratio is used to summarize the degree of program-induced actions. Specifically, the gross energy savings of a program are adjusted to reflect the negative impacts of free ridership and the positive impacts of spillover. Mathematically the ratio is typically expressed as:

NTG ratio = (1-Free ridership) + spillover

Regulators Need Reliable Free Rider/Spillover Estimates: Three Critical Reasons

There are a number of reasons why regulators should strive for, and will benefit from quality evaluation data, especially as it relates to free ridership and spillover measurement. Below are three critical reasons based on the New York experience, but consistent with universal goals of a reasonably priced, secure and environmentally friendly electricity supply:

1. Protect Ratepayers'/Taxpayers' Economic Interests -- Regardless if the energy efficiency investment comes from utilities or public benefits funds, the ratepayer ultimately pays the bill. In the last 10 years, billions of dollars of public funds have been invested in energy efficiency programs. Regulators have a responsibility to monitor the programs to protect the ratepayers' interests by examining the programs for cost effectiveness and responsiveness to program goals and state energy policy. Moreover, having a properly targeted and cost effective energy efficiency portfolio is crucial to making electricity bills more affordable, especially for low-income residents and encouraging economic development.

2. **A Secure Supply of Electricity --** Peak electric demand has been rising significantly in recent years resulting in New York's Independent System Operator (NYISO) to periodically activate emergency demand response programs to avert possible power reserve shortages. In August 2006, New York experienced an hourly average peak load of nearly 34,000 MW. To place this number in context, the peak demand ten years earlier in 1996 was 25,587 MW. The March 2007 NYISO's Reliability Needs Assessment predicts that power deficiencies, primarily in the New York City region, could occur by 2011 and become acute by 2016 if additional energy resources are not acquired. (NYISO, 2007)

As electricity supply becomes tighter, energy efficiency is being increasingly viewed as a resource on par with electric generation, and being able to quantify the impacts of energy efficiency programs is becoming a critical component for both short and long term planning. The bottom line is can regulators and planners trust the energy savings estimates?

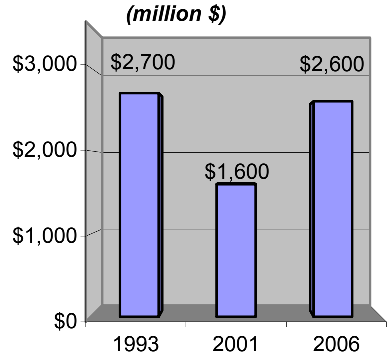
3. Environmental -- Effectively quantifying the benefits of energy efficiency programs is also crucial in understanding the reduction of greenhouse gas emissions resulting from electric generation. The power generation sector contributes an estimated 25 percent of New York's total greenhouse emissions. Regulation currently under consideration for implementing the Regional Greenhouse Gas Initiative (RGGI) requires New York to cap or limit the total $C0_2$ emissions to approximately current levels beginning in 2009 through 2015; and then begin to reduce CO_2 emissions incrementally over a four –year period to achieve a 10 percent reduction by 2019.

Free Rider/Spillover Measurement: A Brief History

In recent years, there has been a renewed interest in free ridership and spillover. The interest level, not surprisingly, correlates with the fluctuating investment levels in energy efficiency programs over the past approximately twenty years.

In the late 1980s, utility industry investment in energy efficiency programs began to rise dramatically. Nationally, spending rose from about $873 million in 1989 to about $2.7 billion by 1993 (Battles 2005, 9). As the size of the investment rose, the need for accurately documenting net program impacts became increasingly critical, and interest in free ridership and, to a lesser extent, spillover grew.

Figure I -- U.S. Spending on Energy Efficiency - Selected Years
(million $)



For a variety of reasons -- most notably the deregulation of the electricity industry, increased availability of energy efficient products and generally ample electricity reserves -- investment in energy efficiency programs began to decline in the late 1990s. By 2001, spending on energy efficiency programs fell by nearly 50 percent from the 1993 level, to about $1.6 billion (Battles 2005, 9).

More recently, energy efficiency program budgets have been rising sharply. This renewed interest in energy efficiency is attributable to a number of factors including increased concern over global warming; accelerating energy prices; and strains on the electricity infrastructure in keeping pace with increasing demand. In 2006, expenditures for energy efficiency programs were conservatively estimated at about $2.6 billion (Consortium for Energy Efficiency, 2007, 4). Adjusted for inflation however, spending is still below the 1993 levels. Using the Consumer Price Index, the 1993 spending level would be the equivalent of about $3.8 billion in 2007 dollars, but indications are that the spending will continue to rise over the foreseeable future. In September 2005, for example, the California Public Utilities Commission created “the most ambitious energy efficiency and conservation campaign in the history of the United States, approving $2 billion in energy efficiency funding for the state's utilities for 2006-2008.” Energy efficiency is described as “California’s highest priority resource for meeting its energy needs in a clean, reliable and low-cost manner.” (California Public Utilities Commission, 2007)

Energy Program Spending in New York State

In New York State, utility spending peaked in 1993 at nearly $300 million, and declined to well under $100 million in the mid nineties. In 1996, the New York State Public Service Commission (PSC) called for the establishment of a System Benefits Charge (SBC) to fund public policy initiatives, such as energy programs, not expected to be adequately addressed by New York's competitive electricity markets. In 1998, the PSC specified a three-year SBC budget of $234 million and the framework for energy programs targeting efficiency measures, research and development and the low-income sector. The SBC programs are designed to serve the diverse needs of New York energy consumers from upstate dairy farmers to office towers in New York City. The SBC program portfolio is primarily administered by a statewide administrator, NYSERDA.

The SBC was renewed for a five-year period in 2001 with increased funding ($150 million per year) and additional focus on programs designed to achieve peak load reductions. In December 2005, the PSC extended the SBC program for an additional five-year period (7/1/2006-6/30/2011) with an annual funding level of $175 million.[1] Currently, the role of the utilities in energy efficiency programs in New York is limited, but annual spending on energy efficiency programs is roughly $300 million including the budgets of NYSERDA, the Long Island Power Authority and the New York Power Authority.

Expectations are that investment in energy efficiency will continue to rise. New York's Governor Spitzer proclaimed in his January 2007 State of the State Address that "[I] n order to lower the second highest energy costs in America, we must implement an aggressive conservation strategy led first and foremost by an effort to reduce the state's own energy consumption." In May 2007, the PSC initiated a proceeding to design an electric and natural gas Energy Efficiency Portfolio Standard. The key goal of this ambitious undertaking is to reduce New York's electricity usage 15% from expected levels by 2015 (New York State PSC, Case 07-M-0548).

Reliability of Free Ridership and Spillover Measurement: A Work in Progress

Free Ridership

Over the past three decades, free rider measurement techniques have steadily improved, but there remains a notable variation in the approaches and methodologies used to identify and report free ridership in addition to legitimate questions about the reliability of the data and the role of the results. Documenting what would have happened, absent a program, remains one of the biggest challenges in energy program evaluation.

Early energy program evaluations (pre-1985) primarily focused on government funded energy conservation programs. These pioneering evaluations had many positive qualities, but were often deficient in quantifying program attribution. An Oak Ridge National Laboratory study of those early evaluations found that most (89 percent) failed to adequately address attribution issues. According to the study, "information is collected only on what clients liked, disliked or say they did. These approaches inspire no confidence that any observed savings were indeed caused by the program." (Berry 1985,154-55)

An analysis of free ridership measurement during the period from 1985-1995, reflecting an analysis of about 100 program evaluations from several states, concluded "elaborate and costly energy consumption analysis is frequently compromised by questionable estimates of free ridership…." evaluators have "often failed to fully exploit the value of free rider data to better understand customers and maximize program efficiency." (Saxonis 1995, 847)

Caveats usually surround free rider estimates, even in the most recent and rigorous program evaluations. In a 2006 study reviewing energy program evaluations in California (the 2002-2003 program portfolio), the authors concluded that, in general, evaluation results suffered from three key problems: incompatibility, incompleteness and a lack of rigor. The study also went on to highlight that less than half of the evaluations took free ridership into consideration when reporting energy savings, covering only 29 percent of the reported kWh savings. The study also noted that "the issues of identifying free riders are complicated and estimating highly reliable program-specific free ridership is problematic at best." (TecMarket Works 2006, p. 41, 68-69)

Spillover

Like free ridership, spillover measurement has improved, but it is still evolving. Spillover analysis trails free ridership measurement in the level of research attention and the level of confidence in

[1] Details about the history of the New York's SBC program, including evaluation data, can be found at the PSC's web page (http://www.dps.state.ny.us/sbc.htm).

the reliability of the results. Many regulators and evaluators recognize that energy programs are likely to have a spillover effect, but they often consider it too difficult and too uncertain to measure. In New York, during the peak period of utility energy programs, spillover measurement was virtually ignored. This phenomenon was also true in other regions of the country. A national review of spillover measurement conducted in 1994 found "very few studies have actually applied any method to capture spillover. Of the 38 studies cited…only 11 actually estimated spillover or overall net savings with spillover…the authors concluded that the "need for more applications is evident." (Cambridge Systematics Inc 1994, 3-16). A review of the California program portfolio (2002-2003), about ten years later, found that only a few of the evaluations contained spillover estimates (TecMarket Works 2006, 42).

Overall, the policy for treatment of spillover and free riders can vary significantly from state to state. For example, in 2006, Northeast Energy Efficiency Partnership (NEEP) examined how spillover and free ridership are used in eight northeastern states to adjust energy savings estimates. NEEP found that three states used both free ridership and spillover (Connecticut, Massachusetts, New York); two states required neither (New Jersey and Maine); and two states used spillover data, but not free rider data (New Hampshire and Rhode Island). Vermont used free rider and spillover results, but limited spillover to the non-participant variety (NEEP 2006, 20).

In New York, spillover is an important monitoring tool, especially for NYSERDA programs with a strong market transformation focus. In developing the SBC program, New York's PSC recommended that emphasis be placed on energy efficiency programs capable of "permanently transforming" markets rather than "achieving immediate or customer-specific savings." (New York State PSC 1998, Case 94-E-0952) While spillover is only one tool used by NYSERDA to monitor market trends and transformation, from a regulatory standpoint, it would be inconsistent to require market transformation initiatives, but not allow NYSERDA the opportunity to use spillover measurement to help capture the results.

An Overview of the NYSERDA Free Rider/Spillover Methodology

In New York, free ridership and spillover are both important factors in assessing the effectiveness of NYSERDA's SBC funded portfolio of energy efficiency programs. In the early years of the SBC programs, limitations on evaluation spending restrained NYSERDA's ability to conduct rigorous evaluation, including free ridership and spillover measurement. When the PSC increased the SBC evaluation budget from less than 1 percent to 2 percent, free ridership and spillover measurement became a priority in the enhanced NYSERDA evaluation metrics introduced in 2003. NYSERDA's evaluation program is implemented using a team approach consisting of an experienced internal staff and respected contractors from around the country.

The following is an overview of the approach used by NYSERDA in capturing free ridership and spillover. It is important to note that due to the size and scope of the NYSERDA program portfolio there may be some variations in the evaluation process from program to program, and the methodology has been subject to continual refinements.

For free ridership measurement, NYSERDA employs a multi-question survey approach that has evolved from their own experience and insights from similar research in other states. Importantly, NYSERDA relies on experienced interviewers who are knowledgeable enough to probe respondents for details of program influences and who can characterize the responses in quantitative terms. The core of the approach includes the following steps:

- Directly asking program participants if they would have implemented the same energy efficiency measures without the assistance of the program;

- Asking quantitative and open-ended questions regarding the influence of the program on specific energy related actions;
- Scoring of open-ended responses by experienced interviewers using an established formula to capture the degree of free ridership based on factors such as the timing of measure installation and the energy efficiency and quantity of the measures installed.

The approach to quantifying spillover depends on a multi question survey approach similar to the free rider measurement methodology. For program participants, the core of the research strategy is to determine if participants believe the program experience had any influence on projects not associated with the program and, if an effect exists, quantify the extent of the effect. For example, NYSERDA's residential audit program (Home Performance with ENERGY STAR) evaluation found that contractors associated with the program were transferring many of the program-influenced practices (e.g., high efficiency insulation, ENERGY STAR furnace/boilers) to non-program homes.

For some programs, non-participants were surveyed to determine if they were aware of the NYSERDA program and the extent, if any, the program had any influence on their energy efficiency related behavior. For example, surveys of building owners and architectural/engineering (A&E) firms not participating in NYSERDA's High Performance New Buildings program discovered that 18 percent of these building owners and 13 percent of the A&E firms increased their knowledge of the benefits of energy efficiency improvements either "somewhat" or "a great deal" because of their awareness of the program. Approximately two in five non-participating firms believe the program influenced building/design practices at their firms.

For some evaluations, NYSERDA uses an "Integrated Data Collection Process" to gain participant feedback, in "near real time," to supplement the more traditional retrospective survey efforts. Simply stated, participants are asked to complete an abbreviated survey containing questions related to program attribution soon after their participation in the program. The theory behind this approach is that survey respondents will have a better sense of the factors influencing their decisions the closer the survey is in time to the decision itself. While the approach is not as rigorous as the retrospective approach, it has proved effective in identifying trends and confirming free rider and spillover values in between major evaluation cycles.

The NYSERDA Free Rider/Spillover Results

A review of four years of free rider and spillover data from NYSERDA's SBC funded Energy $mart portfolio found high free rider rates, and even higher spillover rates, in many key programs. The NYSERDA free rider and spillover data are of interest because together they reflect a large percentage of the energy impacts, especially for the C&I portfolio. For example, NYSERDA's high efficiency motors program had a 67 percent free rider rate and a spillover rate of 168 percent; with a positive NTG ratio the program continues to be offered, but with changes in the program design. Using 2006 data, other key findings related to 10 C&I programs (8 expressing MWh saving and two demand response programs with savings expressed as MW) include:

- Six of the ten programs have spillover rates roughly double the free rider rates.
- Nine of the ten programs have free rider rates 24 percent or higher, including 4 with free rider rates of 39 percent or higher.
- About thirty percent or 576,663 MWh, of the reported savings attributable to eight C&I energy efficiency portfolio programs (1,974,174 MWh) are from spillover.
- Eight of the ten programs have spillover rates higher than the free rider rate.
- The unweighted <u>average</u> free rider rate for the eight programs targeting energy efficiency is 38 percent and the unweighted spillover rate is 66 percent. The program weighted average

free rider and spillover rates are 31% and 51%, respectively. The NTG ratio is only slightly above one (1.07)

- The average spillover percentage drops significantly to 17 percent, or about 81 MW, for the two programs associated directly with demand response. The NTG ratio equals one.

For the seven residential programs in our study the NTG ratio equals about one. Approximately 18 percent of the reported 127,060 MWh savings is attributable to spillover or 22,336 MWh. The unweighted average free rider rate is 16 percent (17% program weighted) and the unweighted average spillover rate is about 20 percent (16% program weighted). Table 1 lists the names and types of programs examined in our study and highlights key results.[2] Figures two-four highlight the impact free ridership and spillover have on the NYSERDA program portfolio.

When we examined the free rider and spillover data for both free ridership and spillover over the four-year period (2003-2006), we found relatively little change in the results. In some cases new research was not conducted, but in other cases the results simply didn't change significantly.

Table 1- Program Type and Key Results

	FR (%)	Spillover (%)	NTG (ratio)	Gross Savings	Net Savings
C&I					
Demand Response	24	25	0.95	247	235
Interval Meters	10	22	1.09	216	236
Total (MW)				463	471
Demand Response (permanent)	25	37	1.03	90,560	93,276
C&I Performance	31	44	1.04	731,900	757,427
Smart Equipment	51	45	0.7	112,640	78,848
Lighting	39	79	1.09	33,541	36,559
Motors	67	168	0.88	9,689	8,822
Loan Fund	27	19	0.92	55,717	51,260
New Building	40	85	1.22	205,201	250,345
Flex tech Audit	25	48	1.14	611,962	697,637
Total (MWH)				1,851,210	1,974,174
RESIDENTIAL					
Energy Star	28	48	1.17	7,914	9,259
Home Performance	26	41	1.12	13,031	14,595
Comprehensive Energy	2	18	1.16	3,096	3,592
Multifamily	27	15	0.84	27,511	23,109
Direct Install	N/A	N/A	1	11,494	11,494
Keep Cool (AC)	18	15	0.94	29,460	27,781
Bulk Purchase	10	5	0.95	39,397	37,230
Total (MWH)				131,903	127,060

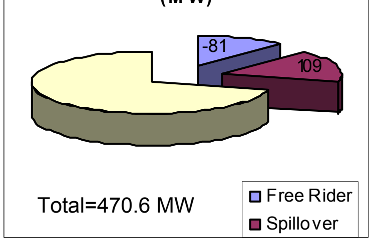


Figure 2
Net Savings w/Free Rider & Spillover Components
C/I Demand Response Programs
(MW)

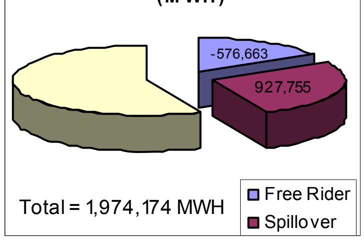


Figure 3
Net Savings w/Free Rider & Spillover Components
C/I Programs
(MWH)

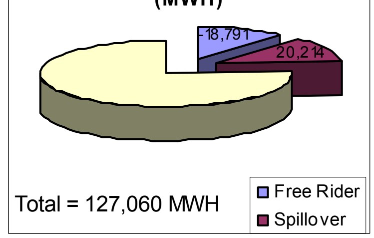


Figure 4
Net Savings w/Free Rider & Spillover Components
Residential Programs
(MWH)

[2] Details about the NYSERDA program portfolio can be found at the NYSERDA web page at http://www.nyserda.org/Energy_Information/evaluation.asp.

Comparing New York's Results to Other States

In the early days of New York utility programs, an acceptable free rider rate was never formally established, but generally a rate of about 20 percent or higher would attract regulatory attention. Spillover data was too limited to develop a benchmark, but by historical standards, rates over 20 percent were unusual. Are these benchmarks still reasonable? One way to better understand the NYSERDA data is to examine similar data from similar programs in other states.

In August 2006, National Grid released a free ridership and spillover study of its 2005 C&I programs offered in New England. The study focused on two programs: Energy Initiative and Design 2000*plus*. The Energy Initiative Program encourages C&I and governmental customers to upgrade to more energy efficient equipment (e.g., lighting, HVAC controls, motors) by covering 50 percent of the total installation costs. Based on 2005 data, the Energy Initiative Program has a free rider rate of 9 percent and a spillover rate of about 4 percent. By contrast, a package of 4 roughly similar NYSERDA programs has, on average, a free rider rate of 47 percent and a spillover rate of 84 percent. The Design 2000*plus* Program targets new construction and major renovation of existing buildings by offering architects, engineers and builders technical and financial assistance to incorporate energy efficient options. The Design 2000*plus* has a free rider rate of approximately 22 percent and a spillover rate of 12 percent (National Grid 2006, 1-12). The roughly equivalent NYSERDA program, High Performance in New Buildings, exhibits a free rider rate of 40 percent and a spillover rate of 85 percent.

Relatively new programs, designed to serve the business sectors in Maine and Oregon, experienced free rider rates of 27 and 17 percent respectively, but spillover of 2 percent or less. In both cases, however, evaluation of non-participant spillover was not included (Maine 2005 4-14, Research into Action, 2005 135). Roughly similar results were experienced in Wisconsin for energy programs targeting the C&I sector (Wisconsin 2007). Examining several utility operated C&I program evaluations in California found spillover rates ranging from 5-21 percent and free rider rates ranging from 30-46 percent. These evaluations were conducted using a variety of methodologies and over a fairly wide time frame, 1999-2006 (Hummer, 2006).

The Regulatory Dilemma: Dealing with Free rider and Spillover Results

While the number of comparable studies is limited, it appears that spillover, and to a lesser extent free ridership, represents a bigger impact in New York compared to other states. Does New York overestimate spillover and free ridership? Are programs in other states underestimating these effects? Is a high free rider rate a cost for having high spillover? Are the estimates generally accurate, but the differences are a result of the program designs? These are all critical questions to understanding spillover and free rider results.

Unfortunately, there are no clearly defined answers to these questions. While this comparative analysis is insightful, interpreting the results needs to be tempered with caution. A variety of factors can influence the results including differences in program design, customer base, age of the program, evaluation period, evaluation methodologies and reporting protocols. It is instructive to note that several of the studies in our comparison, specifically the National Grid, Maine and several of the Wisconsin studies were conducted by the same evaluation firm using a similar survey based approach. This approach is also similar to NYSERDA's methodology as discussed in detail earlier in this paper.

While the evaluations highlighted in our review appear generally sound, we know that measurement of free ridership, and especially spillover, is uncertain even when employing the best techniques and highly skilled evaluators. Even within the studies themselves there is sometimes puzzling results. For example, in the National Grid Design 2000*plus* Program, participant spillover in 2005 in New Hampshire was 28 percent, but less than five percent in Rhode Island, a state less than 100 miles away. In many studies we have seen large differences in spillover and free rider rates from measure to measure. At a micro level, it may be possible to discover possible explanations for the variations, but it would be speculative. Assuming the research doesn't suffer from gross infirmities, it is difficult, perhaps impossible, to conclusively determine if an "unusual" result is a reflection of reality or a flaw in the methods or research implementation. For example, two NYSERDA programs with both high spillover and free rider rates, the High Performance Buildings Program and the Motors program, place a priority on market transformation. This is a plausible explanation for a high spillover rate, and possibly high free ridership, but how do we test the validity of the theory? The California Evaluation Framework concluded, "We can never know the 'true' free rider rate." (TecMarket Works 2004, 140). Spillover is even a greater challenge.

An added dilemma is the impact of free ridership and spillover on NTG ratios. Interestingly, despite the magnitude of the NYSERDA free rider and spillover results, the impact on the NTG ratios of their two major program categories, C&I and residential, is virtually non-existent with NTG ratios of almost exactly one. In states with overall lower free rider and spillover rates, however, the impact on the NTG ratio is sometimes more significant because free ridership tends to be higher than spillover, the opposite of the New York results.

To maximize the value and have a high level of confidence in free rider and spillover data, it is obvious that data quality needs to be improved. This is not a simple or inexpensive task and one that has challenged evaluators for decades.

A Pathway to Better Results

Simply stating a problem is only part of the equation. We know that based on clear evidence:

- For a variety of reasons, including regulatory accountability, it is important to collect free rider and spillover data.
- Free ridership and spillover are major factors in New York energy programs.
- Free ridership and spillover are difficult to measure.
- There is a high level of uncertainty in free ridership and spillover measurement.

Where do we go from here? This paper offers specific recommendations to help improve the research and make the resulting data more useful to regulators and other policy makers. Specific suggestions focus on improving data reliability, leveraging knowledge and using the collaborative process to reduce evaluation costs.

Improve Data Reliability

There are several research challenges. First, it is difficult to determine the research approaches that provide the most reliable results. A lesson learned from our analysis is that it is difficult to conclusively determine why results from similar programs can vary dramatically from study to study, measures to measure and program to program. Are the differences "the truth" or the result of flawed evaluation? There are numerous free rider and spillover studies, but little research has been conducted to quantify free rider and spillover results using multiple approaches in the same study. While we may never have complete confidence in the results, this type of research would help increase confidence in the data especially if multiple approaches produced similar results.

In addition to simply dealing with the fundamental question of data reliability, there are also broader methodical issues that deserve additional attention. For example, a case can be made that spillover research, especially using the survey approach, tends to underestimate spillover simply because it is constrained to a specific period of time and to the knowledge and recollection of the respondent. If a program participant decided to install additional energy efficiency measures, above and beyond the program offerings, two months after the spillover survey, it would not be included in the spillover results. A case can also be made that free ridership is overestimated because of the cumulative influence of energy programs over many years. Even with a well-designed survey, it is unclear how to adjust the data for these factors. Recommendations include:

- Increase emphasis on using additional methods to quantify free rider ship and spillover to "triangulate" the data. This could involve techniques such as comparison groups, statistical models and different survey strategies.
- Increase the precision and confidence levels of survey related work to determine if changes in free rider and spillover rates, especially among specific measures, reflect changes in reaction to the program or statistical noise.
- Employ more long term and comparative analysis.
- Conduct studies that compare adoption of energy efficient products in regions with and without intervention programs to assess the magnitude of the impacts.
- Develop more probing questions that go beyond questions related to specific energy actions.

Leverage Free rider/spillover Data to Maximize Value

Ultimately, measurement of spillover and free ridership attempts to quantify a cause and effect relationship given a constantly changing market environment. A challenge often ignored by evaluators and regulators is understanding the change in free rider and spillover levels as economic conditions and markets evolve. This is especially important as markets evolve at a rate that just a few decades ago would have been considered unimaginable. It is remarkable to reflect upon some of the market changes that likely impacted NYSERDA's programs during our analysis period, 2003-early 2007. For example:

- Residential natural gas prices in New York State rose from about $11.00 (MCF) in December 2003 to over $15.50 in December 2006.
- The price of a barrel of oil more than doubled from about $30 per barrel in 2003 to over $65 per barrel in May 2007.
- A boom in one of the most critical elements of the U.S. economy, housing. For example, home prices in the New York City metro region rose 46 percent between 2003 and the first quarter of 2006 compared to a national increase of 31 percent (National Association of Realtors, 2006).
- Increased interest in environmental issues. A February 2007 survey, conducted for Yale University, found a significant shift in public attitudes toward the environment and global warming. Fully 83 percent of Americans say that global warming is a "serious" problem up from 70 percent in 2004. (Yale Center for Environmental Law and Policy, 2007) The results also suggest that many Americans want "greener" products and are ready to invest in new technologies that will help reduce greenhouse gas emissions.
- Increased sensitivity to environmental concerns from the business community. General Electric made environmental products a key element of its growth strategy, and Wal-Mart established aggressive environmental goals including, "to be supplied 100 percent by renewable energy; to create zero waste; and to sell products that sustain our resources and our environment."(Wal-Mart, 2007)

While spillover and free rider measurement can serve as an indicator of market effects, it is underutilized in this regard. A key concern of New York regulators has focused on determining whether or not SBC funded programs are continuing to be responsive to consumers, the changing marketplace and the State's energy policy objectives. We do not want to continually approve programs simply because they have been offered in the past, but rather because they are meeting today's, not yesterday's needs. There are several ways of gaining insights into these concerns, such as monitoring program application rates, process evaluations, product baselines and customer feedback, but there is no established protocols for using free rider and spillover results to refine or update program designs.

A study suggested that the deteriorating economic climate in New York State during the early 1990s had a direct influence on declining free rider rates in an appliance rebate program as consumers became more intent on finding value in their purchases. During roughly the same period, the utility serving the New York City area, Consolidated Edison, found that electric contractors eager for business aggressively recruited customers to participate in the utility's energy efficient lighting program as a way of replacing lost business. The result was an unexpectedly low free rider rate. (Saxonis 1995, 847-52) Unfortunately, little of this type of innovative research has been conducted.

It is difficult to understand and accurately interpret free rider and spillover data as market indicators based on current measurement techniques. Is a housing boom distorting results from the ENERGY STAR home program? Will the results change as the housing prices decline? If so, how? Is a high free rider rate resulting from the influence of an energy price spike occurring just as consumers are being surveyed or a signal that a program needs to be redesigned? What are the characteristics of free riders and what are the drivers of spillover? We have some ideas, but, at best, our knowledge is sketchy and uncertain.

One way to answer these questions is through more imaginative use of free rider and spillover databases, especially using the data, not simply for calculating cost effectiveness, but also for better understanding program designs, impacts and relevancy, and the marketplace in general. An added bonus is that the value of free rider and spillover data would be significantly enhanced and more justifiable from a cost standpoint if it offered clear benefits as a market indicator and as a tool for program enhancement. Specific recommendations include:

- Link free rider/spillover data with results from questions related to areas such as demographics, attitudes toward the environment and energy efficiency, reasons for program participation, shopping preferences and the status of the economy.
- Conduct longitudinal studies to see how free rider and spillover rates change over time and under what conditions.

Increase Collaboration

NYSERDA has made important strides in the challenging task of quantifying free ridership and spillover. Compounding the challenge is the need to perform many types of evaluations (e.g., measurement and verification, process) within limits of resources and time constraints. Other states are in a similar position. Financial limitations make it difficult to conduct the types of ambitious research advocated in this paper. A possible solution is increased collaboration.

The issue of attribution needs to be discussed in both regional and national forums. Some efforts are already underway. In the New England states, for example, a State Program Working Group is in the process of exploring ways to standardize measurement and verification methods and considering approaches to dealing with energy program attribution issues. Regulators, government leaders, utility managers, evaluators and other interested parties should be encouraged to examine innovative methods to enhance the quality of free rider/spillover measurement and to begin to view the data as a tool for seeing beyond simply calculating B/C ratios. A clear advantage of a collaborative is that methodologically related research studies could be conducted on a group basis, defraying the costs, which has proven to be a major barrier to this type of research. In addition, a collaborative could also serve as a forum for innovative ideas and to consider standardization of definitions and research approaches.

Conclusion

The popular book on management techniques, "First Break all the Rules," begins chapter one with a provocative question: "What do we know to be important but are unable to measure?" The authors then tell the story of how in 1707, Great Britain lost nearly an entire fleet of ships as ships one after another crashed into the rocks of the Scilly Isles. Two thousand sailors died as result of this tragic miscalculation of position. Sailors had understood the concept of longitude and latitude for years, but crude measurement was the problem. A common navigational technique of the era was to drop a log over the side of the boat and time how long it took to float from bow to stern. (Buckingham, 1999, 21)

The concept of free ridership and spillover have been know for years and most agree that properly used and properly understood this data can be an important tool for regulators and others involved in energy efficiency programs. The most important lesson learned is that we need to focus more on improving measurement techniques, not just for computing B/C ratios, but for better understanding energy efficiency programs and markets. While we can't compare the importance of free riders and spillover measurement to the tragedy experienced by Britain's navy, the story does vividly illustrate that it is not sufficient to simply understand a concept, but to have the tools and skill to maximize and apply the concept under real world conditions.

References

Battles, S.J. & Hojjati, B., 2005, "Two Decades of U.S. Household Trends in Energy-Intensity Indicators," Washington D.C.: Energy Information Administration.

Berry, L.G., 1985, "Residential Building Audit Programs," ORNL 6113, Oak Ridge Tenn: Oak Ridge National Laboratory.

Buckingham, M. & Coffman, C., 1999, *First Break All the Rules,* New York: Simon and Schuster.

California Public Utilities Commission, 2007, "The California Story Investing in a Clean Energy Future."

Cambridge Systematics, Inc., 1994, "Program Spillover Effects."

Consortium for Energy Efficiency, 2007, "U.S. Energy-Efficiency Programs a $2.6 Billion Industry."

Hummer, J., 2006, free rider benchmarking spreadsheet, unpublished, Summit Blue Consulting.

Maine Public Utilities Commission, 2006, Evaluation of the Efficiency Maine Business Program-Final Report.

National Association of Realtors, 2006, "Home Price Analysis for New York Region."

National Grid USA, 2006, "2005 Commercial and Industrial Program Free Ridership and Spillover Study Revised, Executive Summary."

New York Independent System Operator, "The NYISO Issues Second Reliability Need Assessment," press release, March 19, 2007.

New York Independent System Operator, "Heat Wave Causes Record Electricity Usage," press release, August 1, 2006.

Northeast Energy Efficiency Partnership, 2006, "The Need for and Approaches to Developing Common Protocols to Measure, Verify and Report Energy Efficiency Savings in the Northeast."

Research into Action, 2005, "Building Efficiency Program: Process & Impact Evaluation-- EOY2."

Saxonis, W.P., 1995, "After Ten Years of Measuring Free Riders: What Have We Learned? What Challenges Remain?" Proceedings of the 1995 International Energy Program Evaluation Conference.

TecMarket Works 2006, "California 2002-2003 Portfolio Energy Efficiency Program Effects and Evaluation Summary Report."

TecMarket Works 2004, "California Evaluation Framework."

New York State Public Service Commission, Opinion 98-3, Case 94-E-0952, In the Matter of Competitive Opportunities Regarding Electric Services, January 30, 1998, Appendix A.

New York State Public Service Commission, Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, May 16, 2007.

Wal-Mart, overview of environmental policy, from corporate web page (2007): http://walmartstores.com/GlobalWMStoresWeb/navigate.do?catg=345

Wisconsin, see Department of Administration listing of program evaluations of programs targeting C&I programs: http://www.doa.state.wi.us/pagesubtext_detail.asp?linksubcatid=562&linkcatid=288&linkid=

Yale Center for Environmental Law and Policy, "Sea Change in Public Attitudes Toward Global Warming Emerges," press release, March 12, 2007.

Attachment 53.2

2.3 GREENHOUSE GAS EMISSION IMPACTS

For the CPR 2007 study period of F2006 to F2016, inclusive, the greenhouse gas (GHG) emission intensity factor for electricity generation was assumed to be 550 tonnes $CO_{2\ equiv}$ per GWh. This is a proxy electricity emissions factor based on actual values for imported electricity in F2006.

For the CPR 2007 study period of post F2016 to F2026, the GHG emission factor for electricity generation is zero. The selection of a zero emissions factor for the post F2016 study period is based on two factors:

- This study assumes that imports decline linearly to zero by F2016, in keeping with the self-sufficiency goal in the BC Energy Plan.
- BC Hydro will adhere to the B.C. Energy Plan, which requires net zero GHG emissions from new electricity generation projects as well as all existing thermal generation by 2016.

Based on the GHG emission intensity factors noted above, Exhibit 2. 4 summarizes the potential annual reduction in GHG emissions that would occur as a result of the combined electric energy savings shown previously in Exhibit 2.1. The results are presented for each Milestone Year and for both the Upper and Lower Achievable Potential scenarios. In each case, the results shown are for the year shown (i.e., they are not cumulative).

Exhibit 2.4: Annual GHG Emission Reduction from Combined Electric Energy Savings for the Total BC Hydro Service Area, by Milestone Year

Milestone Year	Electric Energy Savings GWh/yr		GHG Emission Reduction Tonnes $CO_{2\ equiv}$/yr	
	Upper Achievable	Lower Achievable	Upper Achievable	Lower Achievable
F2006				
F2011	3,469	1,607	1,907,950	883,850
F2016	7,057	3,612	3,881,350	1,986,600
F2021	10,769	6,167	0	0
F2026	15,072	8,659	0	0

Exhibit 2.5 shows the value of the GHG reduction shown in the preceding Exhibit 2.4. The values shown are based on a current 2007 price of $15[5] per tonne of $CO_{2\ equiv}$ and are discounted back to 2006 using a discount rate of 6%. In the absence of any specific data, the values shown in Exhibit 2.5 do not adjust for future increases in the price of carbon.

[5] It is impossible to know the future price of CO_2 at this time; however, the value of $15 per tonne is currently being used in federal government discussions and was agreed to at a meeting of the External Review Panel in August 2007.

Attachment 54.1

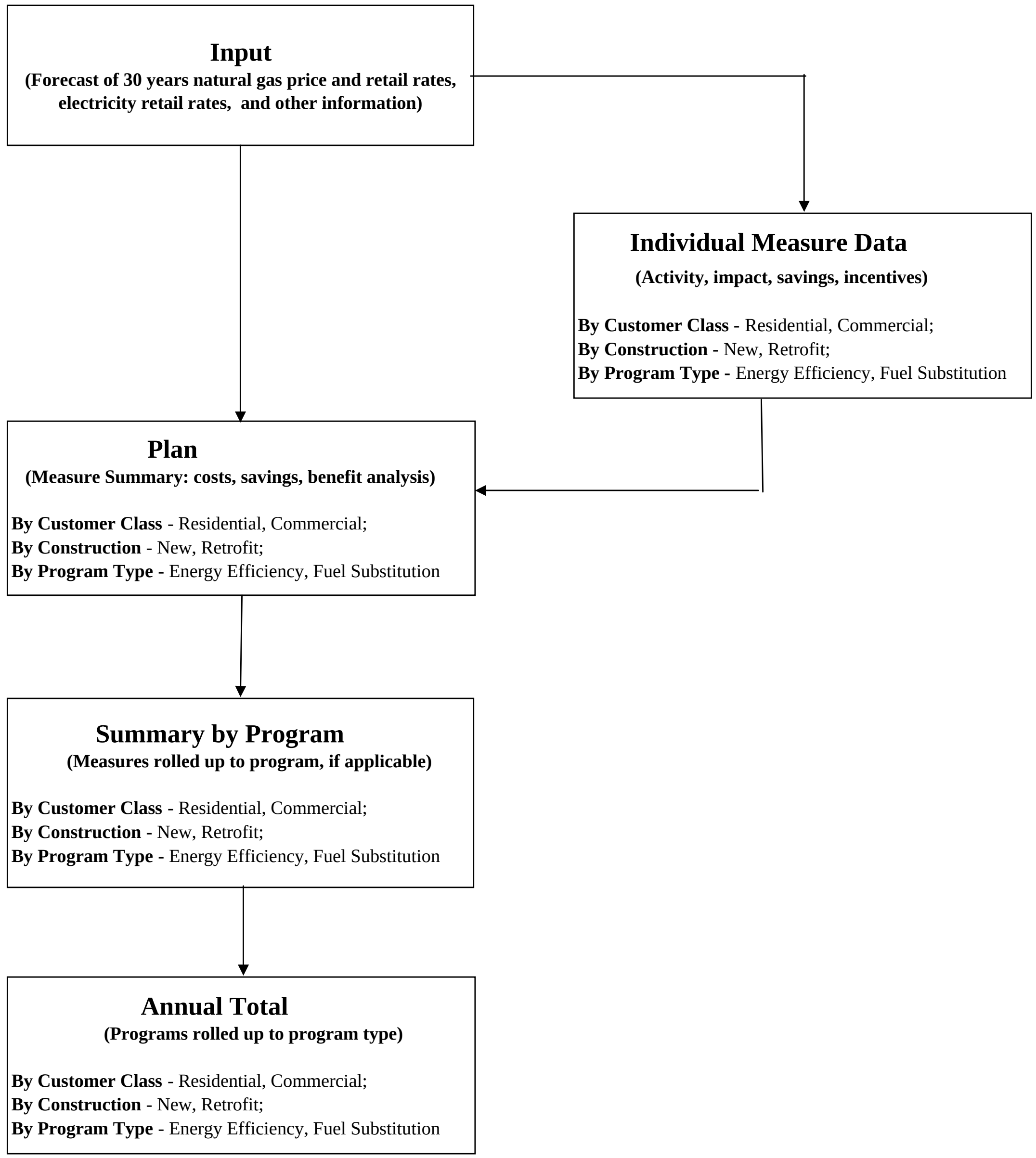
REFER TO ATTACHED SPREADSHEET

Attachment 56.2

Attachment 56.2 A

INCLUDING FREE RIDERS

Table of Contents


Input
(Forecast of 30 years natural gas price and retail rates, electricity retail rates, and other information)
Individual Measure Data
(Activity, impact, savings, incentives)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Plan
(Measure Summary: costs, savings, benefit analysis)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Summary by Program
(Measures rolled up to program, if applicable)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Annual Total
(Programs rolled up to program type)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution

TERASEN GAS INC

		PROGRAM – COSTS ($000) – Utility – Incentives	Utility – Administration	Utility – Total	Participant	Total	% Utility	% Participant	SAVINGS (GJ) – Gross	SAVINGS (GJ) – Net	ALTERNATE Impact – Energy (MWh)	ALTERNATE Impact – Capacity (kW)
	Participants											
2008												
COMMERCIAL:												
New Construction	51	1,136	471	1,607	1,234	2,842	57%	43%	26,902	24,429	2,994	-
Retrofit	198	2,878	818	3,696	2,878	6,575	56%	44%	133,951	113,125	7,650	-
2008 Total Commercial	**249**	**4,014**	**1,289**	**5,303**	**4,113**	**9,416**	**56%**	**44%**	**160,852**	**137,554**	**10,644**	**-**
2009												
COMMERCIAL:												
New Construction	86	2,158	462	2,619	2,361	4,980	53%	47%	48,009	44,081	6,163	-
Retrofit	315	3,802	1,181	4,983	3,802	8,785	57%	43%	190,383	162,250	10,350	-
2009 Total Commercial	**401**	**5,960**	**1,643**	**7,602**	**6,163**	**13,765**	**55%**	**45%**	**238,392**	**206,331**	**16,513**	**-**
2010												
COMMERCIAL:												
New Construction	123	3,408	710	4,117	3,747	7,864	52%	48%	71,755	66,241	10,336	-
Retrofit	441	5,002	1,841	6,843	5,002	11,846	58%	42%	255,033	219,257	17,550	-
2010 Total Commercial	**564**	**8,410**	**2,551**	**10,961**	**8,749**	**19,710**	**56%**	**44%**	**326,789**	**285,498**	**27,886**	**-**
2008 - 2010 (NPV 2007)												
COMMERCIAL:												
New Construction	224	5,759	1,430	7,189	6,308	13,497	53%	47%	126,321	116,025	16,710	-
Retrofit	824	10,145	3,317	13,462	10,145	23,606	57%	43%	502,218	428,608	30,677	-
2008 - 2010 Total Commercial	**1,049**	**15,904**	**4,746**	**20,650**	**16,453**	**37,104**	**56%**	**44%**	**628,540**	**544,633**	**47,387**	**-**

	NET PRESENT VALUE – Levelized Cost ($/GJ)	Utility Benefits (Costs) – Program ($'000s)	Utility Benefits (Costs) – Alternate ($'000s)	Customer Benefits (Costs) – Program ($'000s)	Customer Benefits (Costs) – Carbon Tax ($'000s)	Customer Benefits (Costs) – Alternate ($'000s)	Program Net Savings – Natural Gas (GJ)	Program Net Savings – Alternate Energy (MWh)	Program Net Savings – Alternate Capacity (kW)	BENEFIT/COST – Natural Gas Utility	Participant – Total Costs ($'000s)	Participant – Total Benefits ($'000s)	Participant – Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2008																
COMMERCIAL:																
New Construction	5.7	2,691	4,727	3,562	415	2,136	282,198	36,358	-	1.7	1,234	6,113	5.0	0.5	2.6	4,576
Retrofit	3.0	11,671	6,954	16,727	1,949	3,142	1,231,375	53,489	-	3.2	2,878	21,818	7.6	0.6	2.8	12,050
2008 Total Commercial	**3.5**	**14,361**	**11,680**	**20,290**	**2,363**	**5,277**	**1,513,573**	**89,847**	**-**	**2.7**	**4,113**	**27,930**	**6.8**	**0.6**	**2.8**	**16,625**
2009																
COMMERCIAL:																
New Construction	5.1	5,211	9,730	6,369	783	4,396	510,342	74,844	-	2.0	2,361	11,548	4.9	0.6	3.0	9,961
Retrofit	2.8	17,612	9,408	23,479	2,898	4,251	1,749,147	72,368	-	3.5	3,802	30,627	8.1	0.6	3.1	18,235
2009 Total Commercial	**3.4**	**22,823**	**19,138**	**29,848**	**3,680**	**8,647**	**2,259,489**	**147,212**	**-**	**3.0**	**6,163**	**42,175**	**6.8**	**0.6**	**3.0**	**28,196**
2010																
COMMERCIAL:																
New Construction	5.4	7,919	16,318	9,537	1,219	7,373	768,386	125,520	-	1.9	3,747	18,129	4.8	0.6	3.1	16,372
Retrofit	3.0	23,403	15,952	30,788	3,972	7,208	2,316,289	122,711	-	3.4	5,002	41,968	8.4	0.6	3.3	27,510
2010 Total Commercial	**3.6**	**31,322**	**32,270**	**40,325**	**5,191**	**14,580**	**3,084,675**	**248,231**	**-**	**2.9**	**8,749**	**60,097**	**6.9**	**0.6**	**3.2**	**43,882**
2008 - 2010 (NPV 2007)																
COMMERCIAL:																
New Construction	4.6	15,820	30,774	19,469	2,417	13,904	1,560,925	236,722	-	2.2	6,308	35,790	5.7	0.6	3.5	33,097
Retrofit	2.5	52,686	32,314	70,994	8,818	14,600	5,296,810	248,569	-	3.9	10,145	94,413	9.3	0.6	3.6	61,394
2008 - 2010 Total Commercial	**3.0**	**68,507**	**63,088**	**90,463**	**11,235**	**28,504**	**6,857,736**	**485,291**	**-**	**3.3**	**16,453**	**130,203**	**7.9**	**0.6**	**3.5**	**94,491**

TERASEN GAS INC

	PROGRAM										ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings				Participant					
		Utility									Energy	Capacity	($/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
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2008																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	5	706	160	866	805	1,671	52%	48%	5,486	5,211	2,994	-	14	595	4,727	750	87	2,136	62,135	36,358	-	0.7	805	2,973	3.7	0.4	3.2	3,651
Boilers	13	319	173	492	319	812	61%	39%	11,050	9,061	-	-	5	1,035	0	1,511	176	0	108,034	-	-	2.1	319	1,687	5.3	0.5	1.3	223
Water Heating	33	110	139	249	110	359	69%	31%	10,366	10,157	-	-	2	1,061	0	1,301	152	0	112,028	-	-	4.3	110	1,452	13.2	0.7	3.0	702
Subtotal New Constuction	**51**	**1,136**	**471**	**1,607**	**1,234**	**2,842**	**57%**	**43%**	**26,902**	**24,429**	**2,994**	-	**6**	**2,691**	**4,727**	**3,562**	**415**	**2,136**	**282,198**	**36,358**	-	**1.7**	**1,234**	**6,113**	**5.0**	**0.5**	**2.6**	**4,576**
Retrofit																												
Boilers	80	1,900	177	2,077	1,900	3,977	52%	48%	80,790	65,399	-	-	3	7,469	0	11,051	1,286	0	779,746	-	-	3.6	1,900	12,337	6.5	0.6	1.9	3,492
Building Recommissioning	15	480	195	675	480	1,155	58%	42%	14,625	13,894	6,750	-	7	886	6,136	1,152	134	2,772	98,731	47,197	-	1.3	480	4,058	8.5	0.5	6.1	5,867
Next Generation Building Automa	4	160	59	219	160	379	58%	42%	1,948	1,851	900	-	17	118	818	153	18	370	13,151	6,293	-	0.5	160	541	3.4	0.3	2.5	557
Demand Control Ventilation	40	152	167	319	152	471	68%	32%	13,692	10,269	-	-	3	870	0	1,423	167	0	95,036	-	-	2.7	152	1,590	10.5	0.5	1.8	399
High Efficiency Roof Top Unit	4	18	46	64	18	82	78%	22%	706	706	-	-	8	71	0	87	10	0	7,624	-	-	1.1	18	97	5.4	0.5	0.9	(10)
Water Heating	55	169	175	344	169	512	67%	33%	22,190	21,007	-	-	1	2,257	0	2,862	333	0	237,088	-	-	6.6	169	3,195	19.0	0.7	4.4	1,745
Subtotal Retrofit	**198**	**2,878**	**818**	**3,696**	**2,878**	**6,575**	**56%**	**44%**	**133,951**	**113,125**	**7,650**	-	**3**	**11,671**	**6,954**	**16,727**	**1,949**	**3,142**	**1,231,375**	**53,489**	-	**3.2**	**2,878**	**21,818**	**7.6**	**0.6**	**2.8**	**12,050**
2008 Total Commercial	**249**	**4,014**	**1,289**	**5,303**	**4,113**	**9,416**	**56%**	**44%**	**160,852**	**137,554**	**10,644**	-	**4**	**14,361**	**11,680**	**20,290**	**2,363**	**5,277**	**1,513,573**	**89,847**	-	**2.7**	**4,113**	**27,930**	**6.8**	**0.6**	**2.8**	**16,625**
2009																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	11	1,455	204	1,658	1,658	3,316	50%	50%	11,454	10,881	6,163	-	13	1,335	9,730	1,567	192	4,396	129,738	74,844	-	0.8	1,658	6,155	3.7	0.4	3.3	7,749
Boilers	18	492	116	609	492	1,101	55%	45%	16,620	13,628	-	-	4	1,672	0	2,273	279	0	162,491	-	-	2.7	492	2,552	5.2	0.6	1.5	570
Water Heating	57	211	141	352	211	563	63%	37%	19,935	19,571	-	-	2	2,205	0	2,529	312	0	218,113	-	-	6.3	211	2,841	13.5	0.8	3.9	1,642
Subtotal New Constuction	**86**	**2,158**	**462**	**2,619**	**2,361**	**4,980**	**53%**	**47%**	**48,009**	**44,081**	**6,163**	-	**5**	**5,211**	**9,730**	**6,369**	**783**	**4,396**	**510,342**	**74,844**	-	**2.0**	**2,361**	**11,548**	**4.9**	**0.6**	**3.0**	**9,961**
Retrofit																												
Boilers	93	2,254	210	2,464	2,254	4,718	52%	48%	95,139	77,338	-	-	3	9,486	0	13,013	1,596	0	922,095	-	-	3.8	2,254	14,609	6.5	0.6	2.0	4,767
Building Recommissioning	20	640	237	877	640	1,517	58%	42%	19,500	18,525	9,000	-	7	1,198	8,181	1,536	195	3,696	131,641	62,929	-	1.4	640	5,427	8.5	0.5	6.2	7,862
Next Generation Building Automa	6	240	71	311	240	551	56%	44%	2,922	2,776	1,350	-	16	180	1,227	230	29	554	19,726	9,439	-	0.6	240	814	3.4	0.3	2.6	855
Demand Control Ventilation	80	304	280	584	304	888	66%	34%	27,384	20,538	-	-	3	1,810	0	2,846	357	0	190,072	-	-	3.1	304	3,203	10.5	0.5	2.0	923
High Efficiency Roof Top Unit	6	27	43	70	27	97	72%	28%	1,058	1,058	-	-	6	113	0	130	16	0	11,436	-	-	1.6	27	146	5.4	0.6	1.2	16
Water Heating	110	337	340	677	337	1,014	218%	82%	44,380	42,015	-	-	13	4,825	0	5,724	704	0	474,176	-	-	7.1	337	6,428	19.1	0.8	4.8	3,811
Subtotal Retrofit	**315**	**3,802**	**1,181**	**4,983**	**3,802**	**8,785**	**57%**	**43%**	**190,383**	**162,250**	**10,350**	-	**3**	**17,612**	**9,408**	**23,479**	**2,898**	**4,251**	**1,749,147**	**72,368**	-	**3.5**	**3,802**	**30,627**	**8.1**	**0.6**	**3.1**	**18,235**
2009 Total Commercial	**401**	**5,960**	**1,643**	**7,602**	**6,163**	**13,765**	**55%**	**45%**	**238,392**	**206,331**	**16,513**	-	**3**	**22,823**	**19,138**	**29,848**	**3,680**	**8,647**	**2,259,489**	**147,212**	-	**3.0**	**6,163**	**42,175**	**6.8**	**0.6**	**3.0**	**28,196**
2010																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	19	2,431	342	2,773	2,770	5,543	50%	50%	20,062	19,059	10,336	-	12	2,359	16,318	2,744	350	7,373	227,240	125,520	-	0.9	2,770	10,466	3.8	0.4	3.4	13,133
Boilers	23	665	162	827	665	1,493	55%	45%	22,190	18,196	-	-	4	2,252	0	3,035	387	0	216,948	-	-	2.7	665	3,422	5.1	0.6	1.5	759
Water Heating	81	312	206	517	312	829	62%	38%	29,503	28,986	-	-	2	3,308	0	3,758	483	0	324,198	-	-	6.4	312	4,240	13.6	0.8	4.0	2,479
Subtotal New Constuction	**123**	**3,408**	**710**	**4,117**	**3,747**	**7,864**	**52%**	**48%**	**71,755**	**66,241**	**10,336**	-	**5**	**7,919**	**16,318**	**9,537**	**1,219**	**7,373**	**768,386**	**125,520**	-	**1.9**	**3,747**	**18,129**	**4.8**	**0.6**	**3.1**	**16,372**
Retrofit																												
Boilers	105	2,565	289	2,854	2,565	5,419	53%	47%	107,955	87,897	-	-	3	10,878	0	14,766	1,882	0	1,047,995	-	-	3.8	2,565	16,648	6.5	0.6	2.0	5,459
Building Recommissioning	35	1,120	423	1,543	1,120	2,663	58%	42%	34,125	32,419	15,750	-	7	2,100	14,316	2,687	364	6,468	230,372	110,125	-	1.4	1,120	9,520	8.5	0.5	6.2	13,753
Next Generation Building Automa	8	320	118	438	320	758	58%	42%	3,896	3,701	1,800	-	17	240	1,636	307	42	739	26,301	12,586	-	0.5	320	1,088	3.4	0.3	2.5	1,118
Demand Control Ventilation	120	455	437	892	455	1,348	66%	34%	41,076	30,807	-	-	3	2,734	0	4,269	562	0	285,109	-	-	3.1	455	4,831	10.6	0.5	2.0	1,386
High Efficiency Roof Top Unit	8	36	69	105	36	141	75%	25%	1,411	1,411	-	-	7	153	0	173	22	0	15,248	-	-	1.4	36	196	5.4	0.5	1.1	11
Water Heating	165	506	505	1,011	506	1,516	67%	33%	66,570	63,022	-	-	13	7,299	0	8,586	1,100	0	711,264	-	-	7.2	506	9,686	19.2	0.8	4.8	5,783
Subtotal Retrofit	**441**	**5,002**	**1,841**	**6,843**	**5,002**	**11,846**	**58%**	**42%**	**255,033**	**219,257**	**17,550**	-	**3**	**23,403**	**15,952**	**30,788**	**3,972**	**7,208**	**2,316,289**	**122,711**	-	**3.4**	**5,002**	**41,968**	**8.4**	**0.6**	**3.3**	**27,510**
2010 Total Commercial	**564**	**8,410**	**2,551**	**10,961**	**8,749**	**19,710**	**56%**	**44%**	**326,789**	**285,498**	**27,886**	-	**4**	**31,322**	**32,270**	**40,325**	**5,191**	**14,580**	**3,084,675**	**248,231**	-	**2.9**	**8,749**	**60,097**	**6.9**	**0.6**	**3.2**	**43,882**
2008 - 2010 (NPV 2007)																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	30	3,937	609	4,546	4,486	9,032	50%	50%	31,683	30,099	16,710	-	11	4,289	30,774	5,061	629	13,904	419,113	236,722	-	0.9	4,486	19,595	4.4	0.4	3.9	26,030
Boilers	47	1,278	397	1,676	1,278	2,954	57%	43%	43,179	35,407	-	-	3	4,958	0	6,820	841	0	487,474	-	-	3.0	1,278	7,661	6.0	0.6	1.7	2,004
Water Heating	148	544	423	967	544	1,511	64%	36%	51,459	50,519	-	-	1	6,574	0	7,588	946	0	654,339	-	-	6.8	544	8,534	15.7	0.8	4.3	5,062
Subtotal New Constuction	**224**	**5,759**	**1,430**	**7,189**	**6,308**	**13,497**	**53%**	**47%**	**126,321**	**116,025**	**16,710**	-	**5**	**15,820**	**30,774**	**19,469**	**2,417**	**13,904**	**1,560,925**	**236,722**	-	**2.2**	**6,308**	**35,790**	**5.7**	**0.6**	**3.5**	**33,097**
Retrofit																												
Boilers	243	5,867	587	6,454	5,867	12,321	52%	48%	247,923	201,393	-	-	2	27,833	0	38,830	4,764	0	2,749,836	-	-	4.3	5,867	43,594	7.4	0.6	2.3	15,512
Building Recommissioning	60	1,932	738	2,670	1,932	4,602	58%	42%	58,867	55,924	27,169	-	6	4,184	28,633	5,375	694	12,937	460,744	220,251	-	1.6	1,932	19,006	9.8	0.5	7.1	28,215
Next Generation Building Automa	16	624	215	839	624	1,462	57%	43%	7,592	7,212	3,508	-	14	537	3,681	690	89	1,663	59,178	28,318	-	0.6	624	2,442	3.9	0.4	2.9	2,756
Demand Control Ventilation	206	783	762	1,545	783	2,328	66%	34%	70,626	52,970	-	-	3	5,414	0	8,537	1,086	0	570,217	-	-	3.5	783	9,623	12.3	0.5	2.3	3,087
High Efficiency Roof Top Unit	16	70	138	208	70	278	75%	25%	2,750	2,750	-	-	6	338	0	390	49	0	34,307	-	-	1.6	70	438	6.2	0.6	1.2	60
Water Heating	284	869	877	1,747	869	2,616	67%	33%	114,460	108,360	-	-	1	14,381	0	17,172	2,138	0	1,422,529	-	-	8.2	869	19,310	22.2	0.8	5.5	11,765
Subtotal Retrofit	**824**	**10,145**	**3,317**	**13,462**	**10,145**	**23,606**	**57%**	**43%**	**502,218**	**428,608**	**30,677**	-	**3**	**52,686**	**32,314**	**70,994**	**8,818**	**14,600**	**5,296,810**	**248,569**	-	**3.9**	**10,145**	**94,413**	**9.3**	**0.6**	**3.6**	**61,394**
2008 - 2010 Total Commercial	**1,049**	**15,904**	**4,746**	**20,650**	**16,453**	**37,104**	**56%**	**44%**	**628,540**	**544,633**	**47,387**	-	**3**	**68,507**	**63,088**	**90,463**	**11,235**	**28,504**	**6,857,736**	**485,291**	-	**3.3**	**16,453**	**130,203**	**7.9**	**0.6**	**3.5**	**94,491**

TERASEN GAS INC

		PROGRAM											ALTERNATE	
		COSTS ($000)							SAVINGS (GJ)			LIFE	Impact	
		Utility										Years	Energy	Capacity
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net-to-Gross	Net		MWh	kW
Label		B	C	D	E	F	G	H	Input (program)	J	K	L	M	N
Source Sheet or Calculation		Program	Program	B+C	Program	D+E	D/F	E/F	Program	Program	IxJ	Program	Program	Program
2008														
COMMERCIAL:														
New Construction														
EE Building Design (30% Large)	1	114	96	210	130	340	62%	38%	1,320	95%	1,254	25	502	-
EE Building Design (30% Small)	2	83	32	115	95	210	55%	45%	965	95%	917	25	351	-
EE Building Design (60%)	1	439	32	470	500	970	48%	52%	2,639	95%	2,507	25	2,008	-
High Performance Glazing HIT	1	70	0	70	80	150	47%	53%	562	95%	534	25	133	-
Near Condensing Boiler	8	146	17	163	146	309	53%	47%	5,480	82%	4,494	25	-	-
Condensing Boiler	5	173	156	329	173	502	66%	34%	5,570	82%	4,567	25	-	-
Instantaneous DHW Heater	15	16	97	113	16	129	88%	12%	1,098	85%	933	15	-	-
Condensing DHW Boiler	5	43	5	48	43	90	53%	47%	6,190	100%	6,190	25	-	-
Condensing DHW Heater	8	8	8	16	8	24	67%	33%	862	100%	862	10	-	-
Drainwater Heat Recovery	5	44	29	72	44	116	62%	38%	2,216	98%	2,171	20	-	-
Retrofit														
Near Condensing Boiler	75	1,684	156	1,840	1,684	3,524	52%	48%	73,125	80%	58,500	25	-	-
Condensing Boiler	5	216	20	237	216	453	52%	48%	7,665	90%	6,899	25	-	-
Building Recommissioning	15	480	195	675	480	1,155	58%	42%	14,625	95%	13,894	10	6,750	-
Next Generation Building Automation System	4	160	59	219	160	379	58%	42%	1,948	95%	1,851	10	900	-
Demand Control Ventilation (Large)	20	56	94	150	56	206	73%	27%	9,740	75%	7,305	15	-	-
Demand Control Ventilation (Med)	20	96	73	169	96	265	64%	36%	3,952	75%	2,964	15	-	-
High Efficiency Roof Top Unit	4	18	46	64	18	82	78%	22%	706	100%	706	20	-	-
Instantaneous DHW Heater	20	21	60	81	21	102	79%	21%	1,464	90%	1,318	15	-	-
Condensing DHW Boiler	15	128	45	173	128	300	58%	43%	18,570	95%	17,642	25	-	-
Condensing DHW Heater	20	20	70	90	20	110	82%	18%	2,156	95%	2,048	10	-	-
2008														
Total Commercial	249	4,014	1,289	5,303	4,113	9,416	56%	44%	160,852		137,554		10,644	-
2009														
COMMERCIAL:														
New Construction														
EE Building Design (30% Large)	2	228	99	327	260	587	56%	44%	2,640	95%	2,508	25	1,004	-
EE Building Design (30% Small)	5	208	58	267	238	504	53%	47%	2,413	95%	2,293	25	876	-
EE Building Design (60%)	2	878	47	924	1,000	1,924	48%	52%	5,278	95%	5,014	25	4,016	-
High Performance Glazing HIT	2	140	0	140	160	300	47%	53%	1,123	95%	1,067	25	267	-
Near Condensing Boiler	8	146	17	163	146	309	53%	47%	5,480	82%	4,494	25	-	-
Condensing Boiler	10	346	100	446	346	792	56%	44%	11,140	82%	9,135	25	-	-
Instantaneous DHW Heater	25	26	84	110	26	137	81%	19%	1,830	85%	1,556	15	-	-
Condensing DHW Boiler	10	85	10	95	85	180	53%	47%	12,380	100%	12,380	25	-	-
Condensing DHW Heater	12	12	12	24	12	36	67%	33%	1,294	100%	1,294	10	-	-
Drainwater Heat Recovery	10	88	35	123	88	210	58%	42%	4,431	98%	4,342	20	-	-
Retrofit														
Near Condensing Boiler	85	1,908	177	2,085	1,908	3,994	52%	48%	82,875	80%	66,300	25	-	-
Condensing Boiler	8	346	33	379	346	725	52%	48%	12,264	90%	11,038	25	-	-
Building Recommissioning	20	640	237	877	640	1,517	58%	42%	19,500	95%	18,525	10	9,000	-
Next Generation Building Automation System	6	240	71	311	240	551	56%	44%	2,922	95%	2,776	10	1,350	-
Demand Control Ventilation (Large)	40	112	147	258	112	370	70%	30%	19,480	75%	14,610	15	-	-
Demand Control Ventilation (Med)	40	192	134	326	192	518	63%	37%	7,904	75%	5,928	15	-	-
High Efficiency Roof Top Unit	6	27	43	70	27	97	72%	28%	1,058	100%	1,058	20	-	-
Instantaneous DHW Heater	40	42	120	162	42	204	79%	21%	2,928	90%	2,635	15	-	-
Condensing DHW Boiler	30	255	90	345	255	600	58%	43%	37,140	95%	35,283	25	-	-
Condensing DHW Heater	40	40	130	170	40	210	81%	19%	4,312	95%	4,096	10	-	-
2009														
Total Commercial	401	5,960	1,643	7,602	6,163	13,765			238,392		206,331	390	16,513	0
2010														
COMMERCIAL:														
New Construction														
EE Building Design (30% Large)	5	570	179	749	650	1,399	54%	46%	6,599	95%	6,269	25	2,509	-
EE Building Design (30% Small)	8	333	93	427	380	807	53%	47%	3,861	95%	3,668	25	1,402	-
EE Building Design (60%)	3	1,316	70	1,386	1,500	2,886	48%	52%	7,917	95%	7,521	25	6,024	-
High Performance Glazing HIT	3	211	0	211	240	451	47%	53%	1,685	95%	1,601	25	400	-
Near Condensing Boiler	8	146	17	163	146	309	53%	47%	5,480	82%	4,494	25	-	-
Condensing Boiler	15	519	145	664	519	1,183	56%	44%	16,710	82%	13,702	25	-	-
Instantaneous DHW Heater	35	37	144	181	37	218	83%	17%	2,562	85%	2,178	15	-	-
Condensing DHW Boiler	15	128	15	143	128	270	53%	47%	18,570	100%	18,570	25	-	-
Condensing DHW Heater	16	16	16	32	16	48	67%	33%	1,725	100%	1,725	10	-	-
Drainwater Heat Recovery	15	131	31	162	131	293	55%	45%	6,647	98%	6,514	20	-	-
Retrofit														
Near Condensing Boiler	95	2,133	248	2,381	2,133	4,513	53%	47%	92,625	80%	74,100	25	-	-
Condensing Boiler	10	433	41	473	433	906	52%	48%	15,330	90%	13,797	25	-	-
Building Recommissioning	35	1,120	423	1,543	1,120	2,663	58%	42%	34,125	95%	32,419	10	15,750	-
Next Generation Building Automation System	8	320	118	438	320	758	58%	42%	3,896	95%	3,701	10	1,800	-
Demand Control Ventilation (Large)	60	167	242	410	167	577	71%	29%	29,220	75%	21,915	15	-	-
Demand Control Ventilation (Med)	60	288	194	482	288	770	63%	37%	11,856	75%	8,892	15	-	-
High Efficiency Roof Top Unit	8	36	69	105	36	141	75%	25%	1,411	100%	1,411	20	-	-
Instantaneous DHW Heater	60	63	180	243	63	306	79%	21%	4,392	90%	3,953	15	-	-
Condensing DHW Boiler	45	383	135	518	383	900	58%	43%	55,710	95%	52,925	25	-	-
Condensing DHW Heater	60	60	190	250	60	310	81%	19%	6,468	95%	6,145	10	-	-
2010														
Total Commercial	564	8,410	2,551	10,961	8,749	19,710			326,789		285,498	390	27,886	-

	NET PRESENT VALUE									BENEFIT/COST						
	Levelized Cost	Utility Benefits		Participant Benefits (Costs)			Program Net Savings				Participant					
	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
Source Sheet or Calculation	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2008																
COMMERCIAL:																
New Construction																
EE Building Design (30% Large)	14	143	792	181	21	358	14,950	6,095	-	0.7	130	560	4.3	0.4	2.7	595
EE Building Design (30% Small)	11	105	553	132	15	250	10,934	4,257	-	0.9	95	397	4.2	0.4	3.1	448
EE Building Design (60%)	16	286	3,170	361	42	1,432	29,890	24,385	-	0.6	500	1,835	3.7	0.3	3.6	2,486
High Performance Glazing HIT	11	61	211	77	9	95	6,362	1,621	-	0.9	80	181	2.3	0.4	1.8	121
Near Condensing Boiler	3	513	N/A	750	87	N/A	53,577	-	-	3.1	146	837	5.7	0.6	1.7	204
Condensing Boiler	6	522	N/A	762	89	N/A	54,457	-	-	1.6	173	851	4.9	0.5	1.0	20
Instantaneous DHW Heater	13	79	N/A	114	13	N/A	8,637	-	-	0.7	16	127	8.1	0.3	0.6	(50)
Condensing DHW Boiler	1	707	N/A	847	99	N/A	73,803	-	-	14.9	43	945	22.2	0.8	7.9	617
Condensing DHW Heater	3	55	N/A	68	8	N/A	6,128	-	-	3.4	8	76	9.5	0.7	2.3	31
Drainwater Heat Recovery	3	220	N/A	272	32	N/A	23,459	-	-	3.0	44	304	6.9	0.6	1.9	104
Retrofit																
Near Condensing Boiler	3	6,681	N/A	10,002	1,164	N/A	697,495	-	-	3.6	1,684	11,166	6.6	0.6	1.9	3,157
Condensing Boiler	3	788	N/A	1,048	122	N/A	82,251	-	-	3.3	216	1,170	5.4	0.6	1.7	335
Building Recommissioning	7	886	6,136	1,152	134	2,772	98,731	47,197	-	1.3	480	4,058	8.5	0.5	6.1	5,867
Next Generation Building Automation System	17	118	818	153	18	370	13,151	6,293	-	0.5	160	541	3.4	0.3	2.5	557
Demand Control Ventilation (Large)	2	619	N/A	1,012	119	N/A	67,605	-	-	4.1	56	1,131	20.3	0.5	3.0	413
Demand Control Ventilation (Med)	6	251	N/A	411	48	N/A	27,431	-	-	1.5	96	459	4.8	0.4	0.9	(14)
High Efficiency Roof Top Unit	8	71	N/A	87	10	N/A	7,624	-	-	1.1	18	97	5.4	0.5	0.9	(10)
Instantaneous DHW Heater	7	112	N/A	152	18	N/A	12,194	-	-	1.4	21	170	8.1	0.5	1.1	10
Condensing DHW Boiler	1	2,015	N/A	2,540	296	N/A	210,339	-	-	11.7	128	2,836	22.2	0.7	6.7	1,715
Condensing DHW Heater	6	131	N/A	170	20	N/A	14,555	-	-	1.5	20	190	9.5	0.5	1.2	21
2008																
Total Commercial	4	14,361	11,680	20,290	2,363	5,277	1,513,573	89,847	-	2.7	4,113	27,930	6.8	0.6	2.8	16,625
2009																
COMMERCIAL:																
New Construction																
EE Building Design (30% Large)	11	308	1,585	361	44	716	29,900	12,189	-	0.9	260	1,121	4.3	0.4	3.2	1,305
EE Building Design (30% Small)	10	281	1,384	330	40	625	27,335	10,643	-	1.1	238	996	4.2	0.5	3.3	1,161
EE Building Design (60%)	15	615	6,340	722	89	2,865	59,780	48,769	-	0.7	1,000	3,675	3.7	0.4	3.6	5,031
High Performance Glazing HIT	11	131	422	154	19	190	12,723	3,242	-	0.9	160	363	2.3	0.4	1.8	252
Near Condensing Boiler	3	551	N/A	750	92	N/A	53,577	-	-	3.4	146	841	5.7	0.6	1.8	242
Condensing Boiler	4	1,120	N/A	1,524	187	N/A	108,914	-	-	2.5	346	1,711	4.9	0.6	1.4	329
Instantaneous DHW Heater	8	137	N/A	190	24	N/A	14,396	-	-	1.2	26	214	8.2	0.5	1.0	1
Condensing DHW Boiler	1	1,518	N/A	1,693	208	N/A	147,607	-	-	16.0	85	1,901	22.4	0.8	8.4	1,338
Condensing DHW Heater	3	84	N/A	102	13	N/A	9,192	-	-	3.5	12	115	9.6	0.7	2.3	48
Drainwater Heat Recovery	3	466	N/A	544	67	N/A	46,918	-	-	3.8	88	611	7.0	0.7	2.2	255
Retrofit																
Near Condensing Boiler	3	8,132	N/A	11,336	1,390	N/A	790,494	-	-	3.9	1,908	12,726	6.7	0.6	2.0	4,138
Condensing Boiler	3	1,354	N/A	1,677	206	N/A	131,601	-	-	3.6	346	1,883	5.4	0.7	1.9	629
Building Recommissioning	7	1,198	8,181	1,536	195	3,696	131,641	62,929	-	1.4	640	5,427	8.5	0.5	6.2	7,862
Next Generation Building Automation System	16	180	1,227	230	29	554	19,726	9,439	-	0.6	240	814	3.4	0.3	2.6	855
Demand Control Ventilation (Large)	2	1,288	N/A	2,024	254	N/A	135,211	-	-	5.0	112	2,278	20.4	0.6	3.5	918
Demand Control Ventilation (Med)	6	523	N/A	821	103	N/A	54,862	-	-	1.6	192	924	4.8	0.5	1.0	5
High Efficiency Roof Top Unit	6	113	N/A	130	16	N/A	11,436	-	-	1.6	27	146	5.4	0.6	1.2	16
Instantaneous DHW Heater	7	232	N/A	304	38	N/A	24,388	-	-	1.4	42	342	8.2	0.5	1.1	28
Condensing DHW Boiler	1	4,328	N/A	5,080	623	N/A	420,679	-	-	12.5	255	5,703	22.4	0.8	7.2	3,728
Condensing DHW Heater	6	265	N/A	340	43	N/A	29,110	-	-	1.6	40	383	9.6	0.5	1.3	55
2009																
Total Commercial	3	22,823	19,138	29,848	3,680	8,647	2,259,489	147,212	-	3.0	6,163	42,175	6.8	0.6	3.0	28,196
2010																
COMMERCIAL:																
New Construction																
EE Building Design (30% Large)	10	776	3,962	903	115	1,790	74,749	30,473	-	1.0	650	2,808	4.3	0.5	3.4	3,338
EE Building Design (30% Small)	10	454	2,214	528	67	1,000	43,736	17,029	-	1.1	380	1,596	4.2	0.5	3.3	1,861
EE Building Design (60%)	15	931	9,510	1,083	138	4,297	89,669	73,154	-	0.7	1,500	5,518	3.7	0.4	3.6	7,554
High Performance Glazing HIT	11	198	632	230	29	286	19,085	4,864	-	0.9	240	546	2.3	0.4	1.8	380
Near Condensing Boiler	3	556	N/A	750	96	N/A	53,577	-	-	3.4	146	845	5.8	0.6	1.8	247
Condensing Boiler	4	1,696	N/A	2,286	291	N/A	163,371	-	-	2.6	519	2,577	5.0	0.6	1.4	513
Instantaneous DHW Heater	9	193	N/A	266	35	N/A	20,154	-	-	1.1	37	301	8.2	0.4	0.9	(24)
Condensing DHW Boiler	1	2,298	N/A	2,540	324	N/A	221,410	-	-	16.1	128	2,864	22.5	0.9	8.5	2,028
Condensing DHW Heater	3	112	N/A	136	18	N/A	12,257	-	-	3.5	16	154	9.6	0.7	2.3	64
Drainwater Heat Recovery	2	705	N/A	816	105	N/A	70,377	-	-	4.4	131	921	7.0	0.7	2.4	412
Retrofit																
Near Condensing Boiler	3	9,171	N/A	12,669	1,614	N/A	883,493	-	-	3.9	2,133	14,284	6.7	0.6	2.0	4,657
Condensing Boiler	3	1,708	N/A	2,097	267	N/A	164,501	-	-	3.6	433	2,364	5.5	0.7	1.9	802
Building Recommissioning	7	2,100	14,316	2,687	364	6,468	230,372	110,125	-	1.4	1,120	9,520	8.5	0.5	6.2	13,753
Next Generation Building Automation System	17	240	1,636	307	42	739	26,301	12,586	-	0.5	320	1,088	3.4	0.3	2.5	1,118
Demand Control Ventilation (Large)	2	1,945	N/A	3,037	400	N/A	202,816	-	-	4.7	167	3,437	20.5	0.6	3.4	1,368
Demand Control Ventilation (Med)	6	789	N/A	1,232	162	N/A	82,293	-	-	1.6	288	1,394	4.8	0.5	1.0	19
High Efficiency Roof Top Unit	7	153	N/A	173	22	N/A	15,248	-	-	1.4	36	196	5.4	0.5	1.1	11
Instantaneous DHW Heater	7	351	N/A	456	60	N/A	36,582	-	-	1.4	63	517	8.2	0.5	1.1	45
Condensing DHW Boiler	1	6,550	N/A	7,620	971	N/A	631,018	-	-	12.7	383	8,591	22.5	0.8	7.3	5,650
Condensing DHW Heater	6	398	N/A	509	69	N/A	43,664	-	-	1.6	60	578	9.6	0.5	1.3	88
2010																
Total Commercial	4	31,322	32,270	40,325	5,191	14,580	3,084,675	248,231	-	2.9	8,749	60,097	6.9	0.6	3.2	43,882

		SHEET LABELS
	Residential	
New Construction		
	EE Building Design (30% Large)	**EnerEffBldg Large**
	EE Building Design (30% Small)	**EnerEffBldg Small**
	EE Building Design (60%)	**EEBldg 60%**
	High Performance Glazing HIT	**HP Glazing Unit**
	Near Condensing Boiler	**NearCond Boilers**
	Condensing Boiler	**Cond Boilers**
	Instantaneous DHW Heater	**Inst DHW Heaters**
	Condensing DHW Boiler	**Cond DHW Boilers**
	Condensing DHW Heater	**Cond DHW Heaters**
	Drainwater Heat Recovery	**Drainwater Heat Rec**
Retrofit		
	Near Condensing Boiler	**Retrofit NearCondBoilers**
	Condensing Boiler	**Retrofit CondBoilers**
	Building Recommissioning	**Retrofit Bldg Re-Comm**
	Next Generation Building Automation System	**Retrofit NextGenBAS**
	Demand Control Ventilation (Large)	**Retrofit DemCtlVent (Large)**
	Demand Control Ventilation (Med)	**Retrofit DemCtlVent (Med)**
	High Efficiency Roof Top Unit	**Retrofit HE Roof Top**
	Instantaneous DHW Heater	**Retrofit Inst DHW Heaters**
	Condensing DHW Boiler	**Retrofit Cond DHW Boilers**
	Condensing DHW Heater	**Retrofit Cond DHW Heaters**

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for EE Building Design (30% Large)

PER MEASURE

Total Cost	$ 260,000		
Incentive	**$ 130,000**	$114,084	Present Value accounts for any implementation lag
Participant	**$ 130,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time lag to implementation	**2**	Years		
Energy Savings per installation	**1,504**	GJ	1,320	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**5%**	95%		Net-to-Gross
Alternate Energy Impact	**2,030**	GJ	501,859	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	7	8	**1**	**2**	**5**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	8,978	10,559	1,320	2,640	6,599	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	8,529	10,031	1,254	2,508	6,269	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	3,413,839	4,014,873	501,859	1,003,718	2,509,296	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 1,226,669	$ 1,226,669	$ 143,201	$ 307,581	$ 775,886	
Utility Program Costs						
DSM Incentives		$ 912,670	$ 114,084	$ 228,168	$ 570,419	Including Implementation Lag
Administration		$ 373,664	**$ 96,333**	**$ 98,666**	**$ 178,665**	
Subtotal	$ 1,099,750	$ 1,286,334	$ 210,417	$ 326,834	$ 749,084	
Participants' Net Costs						
Incremental Cost		$ 1,040,000	$ 130,000	$ 260,000	$ 650,000	
Subtotal	$ 884,310	$ 1,040,000	$ 130,000	$ 260,000	$ 650,000	
Alternate Savings - Net						
Energy (Purchases)		$ 6,338,459	$ 792,307	$ 1,584,615	$ 3,961,537	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 6,338,459	$ 6,338,459	$ 792,307	$ 1,584,615	$ 3,961,537	
Net Present Benefit (Cost)	$ 5,581,067	$ 5,238,793	$ 595,091	$ 1,305,363	$ 3,338,339	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.8**		**2.7**	**3.2**	**3.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 19.5**		**$ 22.8**	**$ 19.6**	**$ 18.7**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for EE Building Design (30% Small)

PER MEASURE

Total Cost	$ 95,000		
Incentive	**$ 47,500**	$41,684	Present Value accounts for any implementation lag
Participant	**$ 47,500**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	**2**	Years		
Energy Savings per installation	**550.0**	GJ	483	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**5%**	95%		Net-to-Gross
Alternate Energy Impact	**709.0**	GJ	175,280	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	13	15	**2**	**5**	**8**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	6,196	7,240	965	2,413	3,861	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	5,887	6,878	917	2,293	3,668	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	2,250,269	2,629,198	350,560	876,399	1,402,239	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 839,910	$ 839,910	$ 104,735	$ 281,200	$ 453,976	
Utility Program Costs						
DSM Incentives		$ 625,267	$ 83,369	$ 208,422	$ 333,476	Including Implementation Lag
Administration		$ 183,331	**$ 31,666**	**$ 58,333**	**$ 93,332**	
Subtotal	$ 692,734	$ 808,598	$ 115,035	$ 266,755	$ 426,808	
Participants' Net Costs						
Incremental Cost		$ 712,500	$ 95,000	$ 237,500	$ 380,000	
Subtotal	$ 609,812	$ 712,500	$ 95,000	$ 237,500	$ 380,000	
Alternate Savings - Net						
Energy (Purchases)		$ 4,150,832	$ 553,444	$ 1,383,611	$ 2,213,777	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 4,150,832	$ 4,150,832	$ 553,444	$ 1,383,611	$ 2,213,777	
Net Present Benefit (Cost)	$ 3,688,196	$ 3,469,644	$ 448,144	$ 1,160,555	$ 1,860,945	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.8**		**3.1**	**3.3**	**3.3**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 18.6**		**$ 19.2**	**$ 18.4**	**$ 18.4**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for EE Building Design (60%)

PER MEASURE

Total Cost	$ 1,000,000		
Incentive	**$ 500,000**	$438,784	Present Value accounts for any implementation lag
Participant	**$ 500,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	**2**	Years		
Energy Savings per installation	**3007.0**	GJ	2,639	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**5%**	95%		Net-to-Gross
Alternate Energy Impact	**8122.0**	GJ	2,007,931	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	5	6	**1**	**2**	**3**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	13,612	15,833	2,639	5,278	7,917	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	12,931	15,041	2,507	5,014	7,521	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	10,357,307	12,047,586	2,007,931	4,015,862	6,023,793	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 1,832,019	$ 1,832,019	$ 286,306	$ 614,958	$ 930,754	
Utility Program Costs						
DSM Incentives		$ 2,632,702	$ 438,784	$ 877,567	$ 1,316,351	Including Implementation Lag
Administration		$ 148,331	**$ 31,666**	**$ 46,666**	**$ 69,999**	
Subtotal	$ 2,391,496	$ 2,781,033	$ 470,450	$ 924,233	$ 1,386,350	
Participants' Net Costs						
Incremental Cost		$ 3,000,000	$ 500,000	$ 1,000,000	$ 1,500,000	
Subtotal	$ 2,579,099	$ 3,000,000	$ 500,000	$ 1,000,000	$ 1,500,000	
Alternate Savings - Net						
Energy (Purchases)		$ 19,020,060	$ 3,170,010	$ 6,340,020	$ 9,510,030	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 19,020,060	$ 19,020,060	$ 3,170,010	$ 6,340,020	$ 9,510,030	
Net Present Benefit (Cost)	$ 15,881,484	$ 15,071,045	$ 2,485,866	$ 5,030,745	$ 7,554,434	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.2**		**3.6**	**3.6**	**3.6**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 32.2**		**$ 32.5**	**$ 32.2**	**$ 32.2**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for High Performance Glazing HIT

PER MEASURE

Total Cost	$ 160,000		
Incentive	**$ 80,000**	$70,205	Present Value accounts for any implementation lag
Participant	**$ 80,000**		

Annual Impact Per Measure				Average Annnual Energy Savings per Measure
Time to impementation	**2**	Years		
Energy Savings per installation	**640.0**	GJ	562	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**5%**	95%		Net-to-Gross
Alternate Energy Impact	**540.0**	GJ	133,499	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	5	6	**1**	**2**	**3**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	2,897	3,370	562	1,123	1,685	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	2,752	3,201	534	1,067	1,601	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	688,617	800,997	133,499	266,999	400,498	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 389,921	$ 389,921	$ 60,936	$ 130,886	$ 198,099	
Utility Program Costs						
DSM Incentives		$ 421,232	$ 70,205	$ 140,411	$ 210,616	Including Implementation Lag
Administration		$ -	$ -	$ -	$ -	
Subtotal	$ 362,133	$ 421,232	$ 70,205	$ 140,411	$ 210,616	
Participants' Net Costs						
Incremental Cost		$ 480,000	$ 80,000	$ 160,000	$ 240,000	
Subtotal	$ 412,656	$ 480,000	$ 80,000	$ 160,000	$ 240,000	
Alternate Savings - Net						
Energy (Purchases)		$ 1,264,569	$ 210,762	$ 421,523	$ 632,285	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 1,264,569	$ 1,264,569	$ 210,762	$ 421,523	$ 632,285	
Net Present Benefit (Cost)	$ 879,701	$ 753,258	$ 121,493	$ 251,998	$ 379,767	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.1**		**1.8**	**1.8**	**1.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 23.6**		**$ 23.6**	**$ 23.6**	**$ 23.6**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Near Condensing Boiler

PER MEASURE

Total Cost	$ 36,600		
Incentive	**$ 18,300**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 18,300**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**685.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**18%**	82%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	21	24	**8**	**8**	**8**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	14,448	16,440	5,480	5,480	5,480	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	11,847	13,481	4,494	4,494	4,494	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 1,620,477	$ 1,620,477	$ 513,201	$ 551,154	$ 556,123	
Utility Program Costs						
DSM Incentives		$ 439,200	$ 146,400	$ 146,400	$ 146,400	Including Implementation Lag
Administration		$ 49,998	**$ 16,666**	**$ 16,666**	**$ 16,666**	
Subtotal	$ 429,915	$ 489,198	$ 163,066	$ 163,066	$ 163,066	
Participants' Net Costs						
Incremental Cost		$ 439,200	$ 146,400	$ 146,400	$ 146,400	
Subtotal	$ 385,976	$ 439,200	$ 146,400	$ 146,400	$ 146,400	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 804,587	$ 692,079	$ 203,735	$ 241,688	$ 246,657	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.0**		**1.7**	**1.8**	**1.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.8**		**$ 5.8**	**$ 5.8**	**$ 5.8**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Condensing Boiler

PER MEASURE

Total Cost	$ 69,200		
Incentive	$ 34,600		No Implementation Present Value accounts for any implementation lag
Participant	$ 34,600		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	1114.0	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	18%	82%	Net-to-Gross
Alternate Energy Impact	0.0	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	26	30	5	10	15	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	28,731	33,420	5,570	11,140	16,710	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	23,560	27,404	4,567	9,135	13,702	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 3,337,808	$ 3,337,808	$ 521,629	$ 1,120,411	$ 1,695,768	
Utility Program Costs						
DSM Incentives		$ 1,038,000	$ 173,000	$ 346,000	$ 519,000	Including Implementation Lag
Administration		$ 401,164	$ 156,082	$ 99,833	$ 145,249	
Subtotal	$ 1,245,602	$ 1,439,164	$ 329,082	$ 445,833	$ 664,249	
Participants' Net Costs						
Incremental Cost		$ 1,038,000	$ 173,000	$ 346,000	$ 519,000	
Subtotal	$ 892,368	$ 1,038,000	$ 173,000	$ 346,000	$ 519,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 1,199,838	$ 860,644	$ 19,547	$ 328,578	$ 512,519	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.6**		**1.0**	**1.4**	**1.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 7.6**		**$ 9.2**	**$ 7.3**	**$ 7.2**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Instantaneous DHW Heater

PER MEASURE

Total Cost	$ 2,100		
Incentive	$ 1,050	No Implementation	Present Value accounts for any implementation lag
Participant	$ 1,050		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	73.2	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	15%	85%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	15	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	65	75	15	25	35	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	4,741	5,490	1,098	1,830	2,562	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	4,030	4,667	933	1,556	2,178	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$88.15	$88.75	
Energy Purchases	$ 409,437	$ 409,437	$ 79,051	$ 137,115	$ 193,272	
Utility Program Costs						
DSM Incentives		$ 78,750	$ 15,750	$ 26,250	$ 36,750	Including Implementation Lag
Administration		$ 325,333	$ 97,333	$ 84,000	$ 144,000	
Subtotal	$ 351,280	$ 404,083	$ 113,083	$ 110,250	$ 180,750	
Participants' Net Costs						
Incremental Cost		$ 78,750	$ 15,750	$ 26,250	$ 36,750	
Subtotal	$ 68,002	$ 78,750	$ 15,750	$ 26,250	$ 36,750	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ (9,845)	$ (73,396)	$ (49,782)	$ 615	$ (24,228)	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.0**		**0.6**	**1.0**	**0.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 11.2**		**$ 14.9**	**$ 9.5**	**$ 10.8**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Condensing DHW Boiler

PER MEASURE

Total Cost	$ 17,000		
Incentive	$ 8,500	No Implementation	Present Value accounts for any implementation lag
Participant	$ 8,500		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	1238.0	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%	Net-to-Gross
Alternate Energy Impact	0.0	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	26	30	5	10	15	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	31,929	37,140	6,190	12,380	18,570	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	31,929	37,140	6,190	12,380	18,570	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 4,523,588	$ 4,523,588	$ 706,942	$ 1,518,444	$ 2,298,202	
Utility Program Costs						
DSM Incentives		$ 255,000	$ 42,500	$ 85,000	$ 127,500	Including Implementation Lag
Administration		$ 30,000	$ 5,000	$ 10,000	$ 15,000	
Subtotal	$ 245,014	$ 285,000	$ 47,500	$ 95,000	$ 142,500	
Participants' Net Costs						
Incremental Cost		$ 255,000	$ 42,500	$ 85,000	$ 127,500	
Subtotal	$ 219,223	$ 255,000	$ 42,500	$ 85,000	$ 127,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 4,059,350	$ 3,983,588	$ 616,942	$ 1,338,444	$ 2,028,202	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**9.7**		**7.9**	**8.4**	**8.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 1.2**		**$ 1.2**	**$ 1.2**	**$ 1.2**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Condensing DHW Heater

PER MEASURE

Total Cost	$ 2,000		
Incentive	$ 1,000	No Implementation	Present Value accounts for any implementation lag
Participant	$ 1,000		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	107.8	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%	Net-to-Gross
Alternate Energy Impact	0.0	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	10	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	31	36	8	12	16	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	3,361	3,881	862	1,294	1,725	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	3,361	3,881	862	1,294	1,725	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$63.74	$64.69	$64.78	
Energy Purchases	$ 250,379	$ 250,379	$ 54,969	$ 83,680	$ 111,730	
Utility Program Costs						
DSM Incentives		$ 36,000	$ 8,000	$ 12,000	$ 16,000	Including Implementation Lag
Administration		$ 36,000	$ 8,000	$ 12,000	$ 16,000	
Subtotal	$ 62,357	$ 72,000	$ 16,000	$ 24,000	$ 32,000	
Participants' Net Costs						
Incremental Cost		$ 36,000	$ 8,000	$ 12,000	$ 16,000	
Subtotal	$ 31,179	$ 36,000	$ 8,000	$ 12,000	$ 16,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 156,843	$ 142,379	$ 30,969	$ 47,680	$ 63,730	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.7**		**2.3**	**2.3**	**2.3**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.9**		**$ 3.9**	**$ 3.9**	**$ 3.9**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Drainwater Heat Recovery

PER MEASURE

Total Cost	$ 17,500		
Incentive	$ 8,750	No Implementation	Present Value accounts for any implementation lag
Participant	$ 8,750		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	443.1	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	2%	98%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	20	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	26	30	5	10	15	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	11,428	13,293	2,216	4,431	6,647	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	11,199	13,027	2,171	4,342	6,514	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$101.17	$107.24	$108.21	
Energy Purchases	$ 1,390,167	$ 1,390,167	$ 219,669	$ 465,661	$ 704,837	
Utility Program Costs						
DSM Incentives		$ 262,500	$ 43,750	$ 87,500	$ 131,250	Including Implementation Lag
Administration		$ 94,581	$ 28,541	$ 35,416	$ 30,624	
Subtotal	$ 308,664	$ 357,081	$ 72,291	$ 122,916	$ 161,874	
Participants' Net Costs						
Incremental Cost		$ 262,500	$ 43,750	$ 87,500	$ 131,250	
Subtotal	$ 225,671	$ 262,500	$ 43,750	$ 87,500	$ 131,250	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.491 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 855,832	$ 770,586	$ 103,628	$ 255,245	$ 411,713	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.6**		**1.9**	**2.2**	**2.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.4**		**$ 4.9**	**$ 4.5**	**$ 4.2**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Near Condensing Boiler

PER MEASURE

Total Cost	$ 44,900		
Incentive	**$ 22,450**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 22,450**		

Annual Impact Per Measure				Average Annnual Energy Savings per Measure
Time to impementation	-	Years		
Energy Savings per installation	**975.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**20%**	80%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	223	255	**75**	**85**	**95**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	217,377	248,625	73,125	82,875	92,625	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	173,902	198,900	58,500	66,300	74,100	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 23,983,538	$ 23,983,538	$ 6,681,114	$ 8,131,894	$ 9,170,530	
Utility Program Costs						
DSM Incentives		$ 5,724,750	$ 1,683,750	$ 1,908,250	$ 2,132,750	Including Implementation Lag
Administration		$ 581,229	**$ 156,244**	**$ 177,076**	**$ 247,909**	
Subtotal	$ 5,510,817	$ 6,305,979	$ 1,839,994	$ 2,085,326	$ 2,380,659	
Participants' Net Costs						
Incremental Cost		$ 5,724,750	$ 1,683,750	$ 1,908,250	$ 2,132,750	
Subtotal	$ 5,005,249	$ 5,724,750	$ 1,683,750	$ 1,908,250	$ 2,132,750	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 13,467,472	$ 11,952,809	$ 3,157,370	$ 4,138,318	$ 4,657,121	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.3**		**1.9**	**2.0**	**2.0**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.1**		**$ 5.1**	**$ 5.1**	**$ 5.1**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Condensing Boiler

PER MEASURE

Total Cost	$ 86,500		
Incentive	**$ 43,250**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 43,250**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**1533.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**10%**	90%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	20	23	**5**	**8**	**10**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	30,546	35,259	7,665	12,264	15,330	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	27,491	31,733	6,899	11,038	13,797	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 3,849,153	$ 3,849,153	$ 787,858	$ 1,353,795	$ 1,707,501	
Utility Program Costs						
DSM Incentives		$ 994,750	$ 216,250	$ 346,000	$ 432,500	Including Implementation Lag
Administration		$ 93,915	**$ 20,416**	**$ 32,666**	**$ 40,833**	
Subtotal	$ 943,134	$ 1,088,665	$ 236,666	$ 378,666	$ 473,333	
Participants' Net Costs						
Incremental Cost		$ 994,750	$ 216,250	$ 346,000	$ 432,500	
Subtotal	$ 861,773	$ 994,750	$ 216,250	$ 346,000	$ 432,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 2,044,246	$ 1,765,738	$ 334,942	$ 629,129	$ 801,668	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.1**		**1.7**	**1.9**	**1.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.5**		**$ 5.5**	**$ 5.5**	**$ 5.5**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Building Recommissioning

PER MEASURE

Total Cost	$ 64,000		
Incentive	**$ 32,000**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 32,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**975.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**5%**	95%		Net-to-Gross
Alternate Energy Impact	**1620.0**	GJ	450,000	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**10**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	60	70	**15**	**20**	**35**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	58,867	68,250	14,625	19,500	34,125	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	55,924	64,838	13,894	18,525	32,419	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	27,601,898	31,500,003	6,750,001	9,000,001	15,750,001	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$63.74	$64.69	$64.78	
Energy Purchases	$ 4,183,953	$ 4,183,953	$ 885,578	$ 1,198,339	$ 2,100,035	
Utility Program Costs						
DSM Incentives		$ 2,240,000	$ 480,000	$ 640,000	$ 1,120,000	Including Implementation Lag
Administration		$ 854,161	**$ 194,582**	**$ 236,665**	**$ 422,914**	
Subtotal	$ 2,669,690	$ 3,094,161	$ 674,582	$ 876,665	$ 1,542,914	
Participants' Net Costs						
Incremental Cost		$ 2,240,000	$ 480,000	$ 640,000	$ 1,120,000	
Subtotal	$ 1,932,044	$ 2,240,000	$ 480,000	$ 640,000	$ 1,120,000	
Alternate Savings - Net						
Energy (Purchases)		$ 28,632,581	$ 6,135,553	$ 8,180,737	$ 14,316,290	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 28,632,581	$ 28,632,581	$ 6,135,553	$ 8,180,737	$ 14,316,290	
Net Present Benefit (Cost)	$ 28,214,800	$ 27,482,373	$ 5,866,550	$ 7,862,411	$ 13,753,412	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**7.1**		**6.1**	**6.2**	**6.2**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 11.6**		**$ 11.7**	**$ 11.5**	**$ 11.6**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Next Generation Building Automation System

PER MEASURE

Total Cost	$ 80,000		
Incentive	$ 40,000	No Implementation	Present Value accounts for any implementation lag
Participant	$ 40,000		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	487.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	5%	95%		Net-to-Gross
Alternate Energy Impact	810.0	GJ	225,000	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	10	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	16	18	4	6	8	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	7,592	8,766	1,948	2,922	3,896	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	7,212	8,328	1,851	2,776	3,701	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	3,561,867	4,050,000	900,000	1,350,000	1,800,000	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$63.74	$64.69	$64.78	
Energy Purchases	$ 537,280	$ 537,280	$ 117,956	$ 179,566	$ 239,758	
Utility Program Costs						
DSM Incentives		$ 720,000	$ 160,000	$ 240,000	$ 320,000	Including Implementation Lag
Administration		$ 248,750	$ 59,167	$ 71,250	$ 118,333	
Subtotal	$ 838,806	$ 968,750	$ 219,167	$ 311,250	$ 438,333	
Participants' Net Costs						
Incremental Cost		$ 720,000	$ 160,000	$ 240,000	$ 320,000	
Subtotal	$ 623,572	$ 720,000	$ 160,000	$ 240,000	$ 320,000	
Alternate Savings - Net						
Energy (Purchases)		$ 3,681,332	$ 818,074	$ 1,227,111	$ 1,636,147	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 3,681,332	$ 3,681,332	$ 818,074	$ 1,227,111	$ 1,636,147	
Net Present Benefit (Cost)	$ 2,756,235	$ 2,529,862	$ 556,863	$ 855,427	$ 1,117,572	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.9**		**2.5**	**2.6**	**2.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 28.5**		**$ 28.8**	**$ 27.9**	**$ 28.8**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Demand Control Ventilation (Large)

PER MEASURE

Total Cost	$ 5,580		
Incentive	$ 2,790	No Implementation	Present Value accounts for any implementation lag
Participant	$ 2,790		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	487.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	25%	75%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	15	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	103	120	20	40	60	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	50,241	58,440	9,740	19,480	29,220	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	37,681	43,830	7,305	14,610	21,915	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$88.15	$88.75	
Energy Purchases	$ 3,851,547	$ 3,851,547	$ 618,734	$ 1,287,848	$ 1,944,965	
Utility Program Costs						
DSM Incentives		$ 334,800	$ 55,800	$ 111,600	$ 167,400	Including Implementation Lag
Administration		$ 483,329	$ 94,166	$ 146,665	$ 242,498	
Subtotal	$ 704,105	$ 818,129	$ 149,966	$ 258,265	$ 409,898	
Participants' Net Costs						
Incremental Cost		$ 334,800	$ 55,800	$ 111,600	$ 167,400	
Subtotal	$ 287,827	$ 334,800	$ 55,800	$ 111,600	$ 167,400	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 2,859,615	$ 2,698,618	$ 412,968	$ 917,983	$ 1,367,667	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	3.9		3.0	3.5	3.4	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 2.8		$ 3.0	$ 2.7	$ 2.8	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Demand Control Ventilation (Med)

PER MEASURE

Total Cost	$ 9,600		
Incentive	**$ 4,800**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 4,800**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**197.6**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**25%**	75%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**15**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	103	120	**20**	**40**	**60**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	20,385	23,712	3,952	7,904	11,856	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	15,289	17,784	2,964	5,928	8,892	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$88.15	$88.75	
Energy Purchases	$ 1,562,763	$ 1,562,763	$ 251,051	$ 522,544	$ 789,168	
Utility Program Costs						
DSM Incentives		$ 576,000	$ 96,000	$ 192,000	$ 288,000	Including Implementation Lag
Administration		$ 400,996	**$ 72,833**	**$ 133,665**	**$ 194,498**	
Subtotal	$ 840,611	$ 976,996	$ 168,833	$ 325,665	$ 482,498	
Participants' Net Costs						
Incremental Cost		$ 576,000	$ 96,000	$ 192,000	$ 288,000	
Subtotal	$ 495,187	$ 576,000	$ 96,000	$ 192,000	$ 288,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 226,965	$ 9,767	$ (13,782)	$ 4,879	$ 18,670	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.2**		**0.9**	**1.0**	**1.0**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 9.4**		**$ 9.7**	**$ 9.4**	**$ 9.4**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for High Efficiency Roof Top Unit

PER MEASURE

Total Cost	$ 9,000		
Incentive	$ 4,500	No Implementation	Present Value accounts for any implementation lag
Participant	$ 4,500		

Annual Impact Per Measure				Average Annnual Energy Savings per Measure
Time to impementation	-	Years		
Energy Savings per installation	176.4	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	20	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	16	18	4	6	8	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	2,750	3,175	706	1,058	1,411	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	2,750	3,175	706	1,058	1,411	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$101.17	$107.24	$108.21	
Energy Purchases	$ 337,594	$ 337,594	$ 71,389	$ 113,499	$ 152,707	
Utility Program Costs						
DSM Incentives		$ 81,000	$ 18,000	$ 27,000	$ 36,000	Including Implementation Lag
Administration		$ 158,083	$ 45,500	$ 43,250	$ 69,333	
Subtotal	$ 207,728	$ 239,083	$ 63,500	$ 70,250	$ 105,333	
Participants' Net Costs						
Incremental Cost		$ 81,000	$ 18,000	$ 27,000	$ 36,000	
Subtotal	$ 70,152	$ 81,000	$ 18,000	$ 27,000	$ 36,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.491 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 59,714	$ 17,511	$ (10,111)	$ 16,249	$ 11,374	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.2**		**0.9**	**1.2**	**1.1**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 9.4**		**$ 10.7**	**$ 8.5**	**$ 9.3**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Instantaneous DHW Heater

PER MEASURE

Total Cost	$ 2,100		
Incentive	**$ 1,050**		No Implementation Present Value accounts for any implementation lag
Participant	**$ 1,050**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	**73.2**	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**10%**	90%	Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	**15**	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	103	120	**20**	**40**	**60**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	7,552	8,784	1,464	2,928	4,392	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	6,796	7,906	1,318	2,635	3,953	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$88.15	$88.75	
Energy Purchases	$ 694,702	$ 694,702	$ 111,601	$ 232,289	$ 350,813	
Utility Program Costs						
DSM Incentives		$ 126,000	$ 21,000	$ 42,000	$ 63,000	Including Implementation Lag
Administration		$ 360,000	**$ 60,000**	**$ 120,000**	**$ 180,000**	
Subtotal	$ 417,814	$ 486,000	$ 81,000	$ 162,000	$ 243,000	
Participants' Net Costs						
Incremental Cost		$ 126,000	$ 21,000	$ 42,000	$ 63,000	
Subtotal	$ 108,322	$ 126,000	$ 21,000	$ 42,000	$ 63,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 168,566	$ 82,702	$ 9,601	$ 28,289	$ 44,813	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.3**		**1.1**	**1.1**	**1.1**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 8.4**		**$ 8.4**	**$ 8.4**	**$ 8.4**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Condensing DHW Boiler

PER MEASURE

Total Cost	$ 17,000		
Incentive	**$ 8,500**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 8,500**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	**1238.0**	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**5%**	95%	Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	77	90	**15**	**30**	**45**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	95,788	111,420	18,570	37,140	55,710	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	90,998	105,849	17,642	35,283	52,925	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 12,892,225	$ 12,892,225	$ 2,014,784	$ 4,327,566	$ 6,549,875	
Utility Program Costs						
DSM Incentives		$ 765,000	$ 127,500	$ 255,000	$ 382,500	Including Implementation Lag
Administration		$ 270,000	**$ 45,000**	**$ 90,000**	**$ 135,000**	
Subtotal	$ 889,789	$ 1,035,000	$ 172,500	$ 345,000	$ 517,500	
Participants' Net Costs						
Incremental Cost		$ 765,000	$ 127,500	$ 255,000	$ 382,500	
Subtotal	$ 657,670	$ 765,000	$ 127,500	$ 255,000	$ 382,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 11,344,765	$ 11,092,225	$ 1,714,784	$ 3,727,566	$ 5,649,875	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**8.3**		**6.7**	**7.2**	**7.3**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 1.4**		**$ 1.4**	**$ 1.4**	**$ 1.4**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Condensing DHW Heater

PER MEASURE

Total Cost	$ 2,000		
Incentive	$ 1,000	No Implementation	Present Value accounts for any implementation lag
Participant	$ 1,000		

Annual Impact Per Measure				Average Annnual Energy Savings per Measure
Time to impementation	-	Years		
Energy Savings per installation	107.8	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	5%	95%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	10	Years		Estimated lifespan of measure

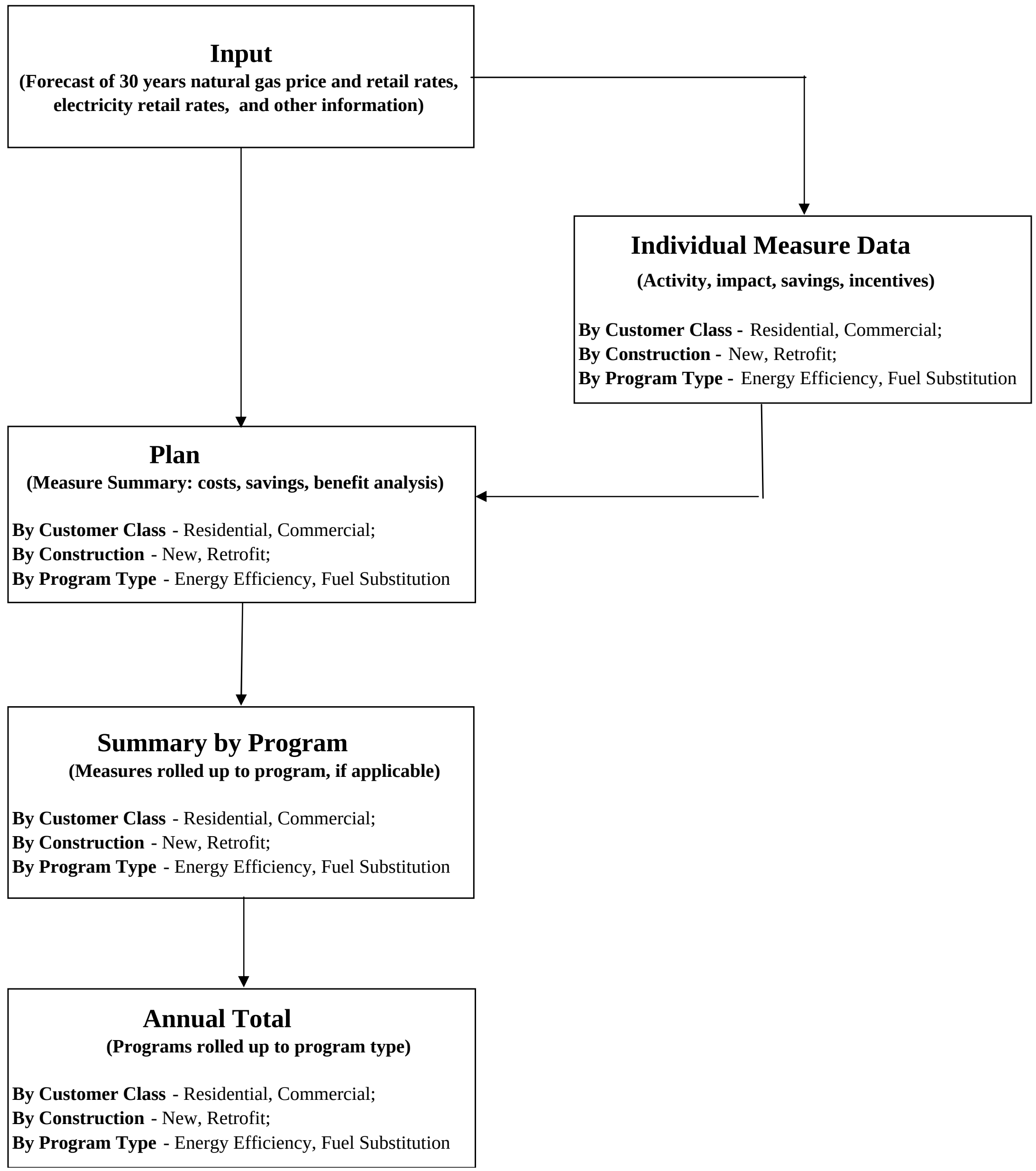
ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	103	120	20	40	60	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	11,121	12,936	2,156	4,312	6,468	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	10,565	12,289	2,048	4,096	6,145	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$63.74	$64.69	$64.78	
Energy Purchases	$ 793,575	$ 793,575	$ 130,551	$ 264,987	$ 398,037	
Utility Program Costs						
DSM Incentives		$ 120,000	$ 20,000	$ 40,000	$ 60,000	Including Implementation Lag
Administration		$ 390,000	$ 70,000	$ 130,000	$ 190,000	
Subtotal	$ 439,020	$ 510,000	$ 90,000	$ 170,000	$ 250,000	
Participants' Net Costs						
Incremental Cost		$ 120,000	$ 20,000	$ 40,000	$ 60,000	
Subtotal	$ 103,164	$ 120,000	$ 20,000	$ 40,000	$ 60,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 251,391	$ 163,575	$ 20,551	$ 54,987	$ 88,037	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	1.5		1.2	1.3	1.3	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 7.2		$ 7.6	$ 7.2	$ 7.1	Informational (for comparison with supply options)

Table of Contents

Sheet Name	Description	MEASURE NAME	PROGRAM NAME
Annual Total	Program Type Summary - costs, savings, and benefit analysis		
Summary by Program	Program Summary - costs, savings, and benefit analysis - annual and total		
Plan	Measures Summary - costs, savings, and benefit analysis - annual		
Input	30 years Natural Gas Price, and other inputs to the model		
FP	Measure data and benefit analysis for Fireplaces (New Construction)	EE EnerChoice Fireplace	EE EnerChoice Fireplace
Estar Clothes	Measure data and benefit analysis for Clothes Washers (New Construction)	EE E* Clothes Washers	EE E* Hot Water Saving Appliances
Estar Dish	Measure data and benefit analysis for Dish Washers (New Construction)	EE E* Dishwashers	EE E* Hot Water Saving Appliances
FS Range	Measure data and benefit analysis for Cooking Ranges (New Construction)	FS Gas Cooking Range	FS Gas Cooking Range
FS Dryer	Measure data and benefit analysis for Clothes Dryers (New Construction)	FS Gas Clothes Dryer	FS Gas Clothes Dryer
Retrofit FP	Measure data and benefit analysis for Fireplaces (Retrofit)	EE E* Furnace Upgrade	EE E* Furnace Upgrade
Retrofit Furnace	Measure data and benefit analysis for Furnace Upgrade (Retrofit)	EE EnerChoice Fireplace	EE EnerChoice Fireplace
Retrofit Estar Dish	Measure data and benefit analysis for Dish Washers (Retrofit)	E* Dishwasher	EE E* Hot Water Saving Appliances
Retrofit Estar Clothes	Measure data and benefit analysis for Clothes Washers (Retrofit)	E* Clothes Washer	EE E* Hot Water Saving Appliances


Input
(Forecast of 30 years natural gas price and retail rates, electricity retail rates, and other information)
Individual Measure Data
(Activity, impact, savings, incentives)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Plan
(Measure Summary: costs, savings, benefit analysis)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Summary by Program
(Measures rolled up to program, if applicable)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Annual Total
(Programs rolled up to program type)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution

TERASEN GAS INC

		PROGRAM									ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings			Natural Gas	Participant			Natural Gas		TRC Net Benefits
		Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity							
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Rate Impact	Total Resource	($'000s)
2008																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	3,000	175	236	411	75	486	85%	15%	10,850	7,974	218	-	5.8	676	175	1,134	126	127	70,962	1,346	-	1.6	75	1,387	18.5	0.4	1.8	366
Fuel Substitution	3,900	195	164	359	-195	164	219%	-119%	-31,770	-19,657	3,883	-	FS	(1,930)	3,566	(3,887)	(431)	2,664	(201,378)	27,432	-	FS	4,318	2,859	0.7	1.7	1.7	1,471
Retrofit																												
Energy Efficiency	10,000	1,750	745	2,495	1,350	3,845	65%	35%	83,600	60,266	715	-	4.2	5,674	584	9,790	1,086	421	592,776	4,493	-	2.3	1,350	11,297	8.4	0.5	1.6	2,412
Fuel Substitution	-	-	-	-	-	- -		-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Subtotals																												
Residential Energy Efficiency	13,000	1,925	981	2,906	1,425	4,331	67%	33%	94,450	68,240	933	-	4.4	6,350	759	10,924	1,212	548	663,739	5,839	-	**2.2**	**1,425**	**12,684**	**8.9**	**0.5**	**1.6**	**2,778**
Residential Fuel Substitution	3,900	195	164	359	-195	164	219%	-119%	-31,770	-19,657	3,883	-	FS	(1,930)	3,566	(3,887)	(431)	2,664	(201,378)	27,432	-	**FS**	**4,318**	**2,859**	**0.7**	**1.7**	**1.7**	**1,471**
2008 Residential Total	**16,900**	**2,120**	**1,145**	**3,265**	**1,230**	**4,495**	**73%**	**27%**	**62,680**	**48,583**	**4,816**	**-**	**7.1**	**4,420**	**4,325**	**7,037**	**781**	**3,212**	**462,361**	**33,271**	**-**							
2009																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	5,500	425	141	566	125	691	82%	18%	23,350	18,133	420	-	3.5	1,544	344	2,474	294	246	163,350	2,648	-	2.7	125	3,014	24.1	0.5	2.7	1,197
Fuel Substitution	5,400	270	139	409	-270	139	294%	-194%	-43,220	-27,043	5,356	-	FS	(2,639)	4,998	(5,288)	(623)	3,674	(277,050)	38,443	-	FS	5,911	3,944	0.7	1.7	1.8	2,220
Retrofit																												
Energy Efficiency	12,500	1,925	733	2,658	1,425	4,083	65%	35%	93,650	67,373	1,060	-	4.0	6,233	864	10,853	1,283	623	656,393	6,648	-	2.3	1,425	12,760	9.0	0.5	1.7	3,014
Fuel Substitution	-	-	-	-	-	- -		-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Subtotals																												
Residential Energy Efficiency	18,000	2,350	874	3,224	1,550	4,774	68%	32%	117,000	85,506	1,480	-	3.9	7,777	1,208	13,326	1,578	869	819,743	9,296	-	**2.4**	**1,550**	**15,774**	**10.2**	**0.5**	**1.9**	**4,211**
Residential Fuel Substitution	5,400	270	139	409	-270	139	294%	-194%	-43,220	-27,043	5,356	-	FS	(2,639)	4,998	(5,288)	(623)	3,674	(277,050)	38,443	-	**FS**	**5,911**	**3,944**	**0.7**	**1.7**	**1.8**	**2,220**
2009 Residential Total	**23,400**	**2,620**	**1,013**	**3,633**	**1,280**	**4,913**	**74%**	**26%**	**73,780**	**58,463**	**6,835**	**-**	**6.7**	**5,138**	**6,206**	**8,038**	**955**	**4,544**	**542,693**	**47,738**	**-**							
2010																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	8,500	775	281	1,056	175	1,231	86%	14%	40,000	32,027	635	-	3.6	2,762	528	4,269	534	373	290,303	4,060	-	2.6	175	5,175	29.6	0.5	2.7	2,059
Fuel Substitution	6,900	345	219	564	-345	219	257%	-157%	-54,670	-34,430	6,828	-	FS	(3,390)	6,429	(6,689)	(824)	4,684	(352,722)	49,454	-	FS	7,513	5,029	0.7	1.7	1.8	2,820
Retrofit																												
Energy Efficiency	11,000	900	467	1,367	300	1,667	82%	18%	48,500	34,736	1,405	-	4.4	2,976	1,144	5,162	646	826	312,847	8,802	-	2.2	300	6,634	22.1	0.5	2.5	2,453
Fuel Substitution	-	-	-	-	-	- -		-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Subtotals																												
Residential Energy Efficiency	19,500	1,675	747	2,422	475	2,897	84%	16%	88,500	66,763	2,040	-	4.0	5,738	1,672	9,430	1,180	1,199	603,151	12,862	-	**2.4**	**475**	**11,809**	**24.9**	**0.5**	**2.6**	**4,512**
Residential Fuel Substitution	6,900	345	219	564	-345	219	257%	-157%	-54,670	-34,430	6,828	-	FS	(3,390)	6,429	(6,689)	(824)	4,684	(352,722)	49,454	-	**FS**	**7,513**	**5,029**	**0.7**	**1.7**	**1.8**	**2,820**
2010 Residential Total	**26,400**	**2,020**	**967**	**2,987**	**130**	**3,117**	**96%**	**4%**	**33,830**	**32,333**	**8,867**	**-**	**11.9**	**2,348**	**8,101**	**2,741**	**356**	**5,883**	**250,428**	**62,315**	**-**							
2008 - 2010 (NPV 2007)																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	14,625	1,174	575	1,749	324	2,073	84%	16%	63,539	49,712	1,094	-	3.3	4,982	1,047	7,877	954	746	524,615	8,053	-	2.8	324	9,576	29.6	0.5	2.9	3,956
Fuel Substitution	14,065	703	457	1,160	(703)	457	254%	-154%	(112,634)	(70,451)	13,951	-	FS	(7,959)	14,993	(15,864)	(1,879)	11,022	(831,150)	115,328	-	FS	17,743	11,726	0.7	1.7	1.8	6,577
Retrofit																												
Energy Efficiency	29,380	4,069	1,725	5,794	2,762	8,556	68%	32%	200,371	144,137	2,755	-	3.7	14,882	2,593	25,804	3,015	1,870	1,562,017	19,943	-	2.6	2,762	30,690	11.1	0.5	2.0	8,919
Fuel Substitution	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Subtotals																												
Residential Energy Efficiency	**44,005**	**5,243**	**2,300**	**7,543**	**3,086**	**10,629**	**71%**	**29%**	**263,910**	**193,849**	**3,849**	**-**	**3.6**	**19,864**	**3,639**	**33,681**	**3,969**	**2,616**	**2,086,632**	**27,996**	**-**	**2.6**	**3,086**	**40,267**	**13.0**	**0.5**	**2.2**	**12,875**
Residential Fuel Substitution	**14,065**	**703**	**457**	**1,160**	**-703**	**457**	**254%**	**-154%**	**-112,634**	**-70,451**	**13,951**	**-**	**FS**	**(7,959)**	**14,993**	**(15,864)**	**(1,879)**	**11,022**	**(831,150)**	**115,328**	**-**	**FS**	**17,743**	**11,726**	**0.7**	**1.7**	**1.8**	**6,577**
2008 - 2010 Total Residential	**58,070**	**5,946**	**2,757**	**8,703**	**2,382**	**11,085**	**79%**	**21%**	**170,290**	**139,379**	**20,519**	**-**	**6.9**	**11,905**	**18,632**	**17,817**	**2,091**	**13,638**	**1,255,482**	**143,324**	**-**							

TERASEN GAS INC

	Participants	PROGRAM COSTS ($000) Utility Incentives	Utility Administration	Utility Total	Participant	Total	% Utility	% Participant	SAVINGS (GJ) Gross	SAVINGS (GJ) Net	ALTERNATE Impact Energy MWh	ALTERNATE Impact Capacity kW	Levelized Cost ($/GJ)	NPV Utility Benefits (Costs) Program ($'000s)	Utility Alternate ($'000s)	Participant Benefits (Costs) Program ($'000s)	Carbon Tax ($'000s)	Participant Alternate ($'000s)	Program Net Savings Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	BENEFIT/COST Natural Gas Utility	Participant Total Costs ($'000s)	Participant Total Benefits ($'000s)	Participant Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2008																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	500	100	101	201	-	201	100%	0%	4,150	3,735	13	-	6	330	14	455	51	8	34,566	109	-	1.6	-	514	N/A	0.5	1.7	143
EE E* Hot Water Saving Appliances	2,500	75	134	209	75	284	74%	26%	6,700	4,239	205	-	6	347	161	679	75	119	36,396	1,236	-	1.7	75	873	11.6	0.4	1.8	223
Subtotal New Constuction Energy Efficiency	**3,000**	**175**	**236**	**411**	**75**	**486**	**85%**	**15%**	**10,850**	**7,974**	**218**	**-**	**6**	**676**	**175**	**1,134**	**126**	**127**	**70,962**	**1,346**	**-**	**1.6**	**75**	**1,387**	**18.5**	**0.4**	**1.8**	**366**
FS Gas Cooking Range	3,000	150	146	296	(150)	146	203%	-103%	(27,900)	(15,903)	3,083	-	FS	(1,562)	2,474	(3,414)	(379)	2,115	(162,921)	19,030	-	FS	3,792	2,265	0.6	1.8	1.4	766
FS Gas Clothes Dryer	900	45	18	63	(45)	18	350%	-250%	(3,870)	(3,754)	800	-	FS	(369)	1,092	(474)	(53)	549	(38,457)	8,402	-	FS	526	594	1.1	1.1	2.8	706
Subtotal New Construction Fuel Substitution	**3,900**	**195**	**164**	**359**	**(195)**	**164**	**219%**	**-119%**	**(31,770)**	**(19,657)**	**3,883**	**-**	**FS**	**(1,930)**	**3,566**	**(3,887)**	**(431)**	**2,664**	**(201,378)**	**27,432**	**-**	**FS**	**4,318**	**2,859**	**0.7**	**1.7**	**1.7**	**1,471**
Retrofit																												
EE E* Furnace Upgrade	4,000	1,200	377	1,577	1,200	2,777	57%	43%	55,200	39,744	-	-	4	3,903	-	6,754	749	-	407,163	-	-	2.5	1,200	7,503	6.3	0.5	1.4	1,126
EE EnerChoice Fireplace	2,000	400	224	624	0	624	100%	0%	16,600	12,616	50	-	5	1,114	48	1,822	202	31	116,757	369	-	1.8	-	2,055	N/A	0.5	1.9	538
EE E* Hot Water Saving Appliances	4,000	150	144	294	150	444	66%	34%	11,800	7,906	665	-	4	656	536	1,214	135	390	68,856	4,124	-	2.2	150	1,739	11.6	0.4	2.7	748
Subtotal Retrofit Energy Efficiency	**10,000**	**1,750**	**745**	**2,495**	**1,350**	**3,845**	**65%**	**35%**	**83,600**	**60,266**	**715**	**-**	**4**	**5,674**	**584**	**9,790**	**1,086**	**421**	**592,776**	**4,493**	**-**	**2.3**	**1,350**	**11,297**	**8.4**	**0.5**	**1.6**	**2,412**
Subtotal Retrofit Fuel Substitution	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**N/A**	**-**	**-**	**N/A**	**N/A**	**N/A**	**N/A**
2008 Subtotal Energy Efficiency	**13,000**	**1,925**	**981**	**2,906**	**1,425**	**4,331**	**67%**	**33%**	**94,450**	**68,240**	**933**	**-**	**4**	**6,350**	**759**	**10,924**	**1,212**	**548**	**663,739**	**5,839**	**-**	**2.2**	**1,425**	**12,684**	**8.9**	**0.5**	**1.6**	**2,778**
2008 Subtotal Fuel Substitution	**3,900**	**195**	**164**	**359**	**-195**	**164**	**219%**	**-119%**	**(31,770)**	**(19,657)**	**3,883**	**-**	**FS**	**(1,930)**	**3,566**	**(3,887)**	**(431)**	**2,664**	**(201,378)**	**27,432**	**-**	**FS**	**4,318**	**2,859**	**0.7**	**1.7**	**1.7**	**1,471**
2008 Total Residential	**16,900**	**2,120**	**1,145**	**3,265**	**1,230**	**4,495**	**73%**	**27%**	**62,680**	**48,583**	**4,816**	**-**	**7**	**4,420**	**4,325**	**7,037**	**781**	**3,212**	**462,361**	**33,271**	**-**	**1.4**	**1,230**	**11,030**	**9.0**	**0.4**	**1.9**	**4,249**
2009																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	1,500	300	41	341	-	341	100%	0%	12,450	11,205	38	-	3	981	43	1,366	162	23	103,699	328	-	2.9	-	1,552	N/A	0.6	3.0	682
EE E* Hot Water Saving Appliances	4,000	125	99	224	125	349	64%	36%	10,900	6,928	382	-	4	563	302	1,107	132	223	59,651	2,320	-	2.5	125	1,462	11.7	0.4	2.5	515
Subtotal New Constuction Energy Efficiency	**5,500**	**425**	**141**	**566**	**125**	**691**	**82%**	**18%**	**23,350**	**18,133**	**420**	**-**	**3**	**1,544**	**344**	**2,474**	**294**	**246**	**163,350**	**2,648**	**-**	**2.7**	**125**	**3,014**	**24.1**	**0.5**	**2.7**	**1,197**
FS Gas Cooking Range	4,000	200	111	311	(200)	111	280%	-180%	(37,200)	(21,204)	4,111	-	FS	(2,069)	3,298	(4,551)	(536)	2,820	(217,227)	25,373	-	FS	5,088	3,020	0.6	1.9	1.5	1,118
FS Gas Clothes Dryer	1,400	70	28	98	(70)	28	350%	-250%	(6,020)	(5,839)	1,244	-	FS	(570)	1,699	(737)	(87)	854	(59,823)	13,070	-	FS	823	924	1.1	1.1	2.8	1,101
Subtotal New Construction Fuel Substitution	**5,400**	**270**	**139**	**409**	**(270)**	**139**	**294%**	**-194%**	**(43,220)**	**(27,043)**	**5,356**	**-**	**FS**	**(2,639)**	**4,998**	**(5,288)**	**(623)**	**3,674**	**(277,050)**	**38,443**	**-**	**FS**	**5,911**	**3,944**	**0.7**	**1.7**	**1.8**	**2,220**
Retrofit																												
EE E* Furnace Upgrade	4,000	1,200	377	1,577	1,200	2,777	57%	43%	55,200	39,744	-	-	4	3,878	-	6,754	796	-	407,163	-	-	2.5	1,200	7,550	6.3	0.5	1.4	1,101
EE EnerChoice Fireplace	2,500	500	203	703	0	703	100%	0%	20,750	15,770	63	-	5	1,380	60	2,277	270	38	145,946	461	-	2.0	-	2,586	N/A	0.5	2.0	737
EE E* Hot Water Saving Appliances	6,000	225	153	378	225	603	63%	37%	17,700	11,859	997	-	4	975	804	1,822	217	585	103,284	6,186	-	2.6	225	2,624	11.7	0.4	2.9	1,176
Subtotal Retrofit Energy Efficiency	**12,500**	**1,925**	**733**	**2,658**	**1,425**	**4,083**	**65%**	**35%**	**93,650**	**67,373**	**1,060**	**-**	**4**	**6,233**	**864**	**10,853**	**1,283**	**623**	**656,393**	**6,648**	**-**	**2.3**	**1,425**	**12,760**	**9.0**	**0.5**	**1.7**	**3,014**
Subtotal Retrofit Fuel Substitution	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**N/A**	**-**	**-**	**N/A**	**N/A**	**N/A**	**N/A**
2009 Subtotal Energy Efficiency	**18,000**	**2,350**	**874**	**3,224**	**1,550**	**4,774**	**68%**	**32%**	**117,000**	**85,506**	**1,480**	**-**	**4**	**7,777**	**1,208**	**13,326**	**1,578**	**869**	**819,743**	**9,296**	**-**	**2.4**	**1,550**	**15,774**	**10.2**	**0.5**	**1.9**	**4,211**
2009 Subtotal Fuel Substitution	**5,400**	**270**	**139**	**409**	**-270**	**139**	**294%**	**-194%**	**(43,220)**	**(27,043)**	**5,356**	**-**	**FS**	**(2,639)**	**4,998**	**(5,288)**	**(623)**	**3,674**	**(277,050)**	**38,443**	**-**	**FS**	**5,911**	**3,944**	**0.7**	**1.7**	**1.8**	**2,220**
2009 Total Residential	**23,400**	**2,620**	**1,013**	**3,633**	**1,280**	**4,913**	**74%**	**26%**	**73,780**	**58,463**	**6,835**	**-**	**7**	**5,138**	**6,206**	**8,038**	**955**	**4,544**	**542,693**	**47,738**	**-**	**1.4**	**1,280**	**13,537**	**10.6**	**0.4**	**2.3**	**6,431**
2010																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	3,000	600	101	701	-	701	100%	0%	24,900	22,410	75	-	3	1,975	85	2,733	341	46	207,397	656	-	2.8	-	3,120	N/A	0.6	2.9	1,358
EE E* Hot Water Saving Appliances	5,500	175	179	354	175	529	67%	33%	15,100	9,617	560	-	4	787	443	1,536	193	327	82,906	3,404	-	2.2	175	2,056	11.7	0.4	2.3	701
Subtotal New Constuction Energy Efficiency	**8,500**	**775**	**281**	**1,056**	**175**	**1,231**	**86%**	**14%**	**40,000**	**32,027**	**635**	**-**	**4**	**2,762**	**528**	**4,269**	**534**	**373**	**290,303**	**4,060**	**-**	**2.6**	**175**	**5,175**	**29.6**	**0.5**	**2.7**	**2,059**
FS Gas Cooking Range	5,000	250	156	406	(250)	156	260%	-160%	(46,500)	(26,505)	5,139	-	FS	(2,610)	4,123	(5,689)	(701)	3,525	(271,534)	31,716	-	FS	6,390	3,775	0.6	1.9	1.5	1,357
FS Gas Clothes Dryer	1,900	95	63	158	(95)	63	251%	-151%	(8,170)	(7,925)	1,689	-	FS	(780)	2,306	(1,000)	(123)	1,159	(81,188)	17,738	-	FS	1,123	1,254	1.1	1.1	2.7	1,463
Subtotal New Construction Fuel Substitution	**6,900**	**345**	**219**	**564**	**(345)**	**219**	**257%**	**-157%**	**(54,670)**	**(34,430)**	**6,828**	**-**	**FS**	**(3,390)**	**6,429**	**(6,689)**	**(824)**	**4,684**	**(352,722)**	**49,454**	**-**	**FS**	**7,513**	**5,029**	**0.7**	**1.7**	**1.8**	**2,820**
Retrofit																												
EE E* Furnace Upgrade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE EnerChoice Fireplace	3,000	600	243	843	-	843	100%	0%	24,900	18,924	75	-	5	1,667	72	2,733	341	46	175,135	554	-	2.0	-	3,120	N/A	0.5	2.1	896
EE E* Hot Water Saving Appliances	8,000	300	223	523	300	823	64%	36%	23,600	15,812	1,330	-	4	1,308	1,072	2,429	305	780	137,712	8,248	-	2.5	300	3,514	11.7	0.4	2.9	1,557
Subtotal Retrofit Energy Efficiency	**11,000**	**900**	**467**	**1,367**	**300**	**1,667**	**82%**	**18%**	**48,500**	**34,736**	**1,405**	**-**	**4**	**2,976**	**1,144**	**5,162**	**646**	**826**	**312,847**	**8,802**	**-**	**2.2**	**300**	**6,634**	**22.1**	**0.5**	**2.5**	**2,453**
Subtotal Retrofit Fuel Substitution	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**N/A**	**-**	**-**	**N/A**	**N/A**	**N/A**	**N/A**
2010 Subtotal Energy Efficiency	**19,500**	**1,675**	**747**	**2,422**	**475**	**2,897**	**84%**	**16%**	**88,500**	**66,763**	**2,040**	**-**	**4**	**5,738**	**1,672**	**9,430**	**1,180**	**1,199**	**603,151**	**12,862**	**-**	**2.4**	**747**	**11,809**	**15.8**	**0.5**	**2.6**	**4,512**
2010 Subtotal Fuel Substitution	**6,900**	**345**	**219**	**564**	**-345**	**219**	**257%**	**-157%**	**(54,670)**	**(34,430)**	**6,828**	**-**	**FS**	**(3,390)**	**6,429**	**(6,689)**	**(824)**	**4,684**	**(352,722)**	**49,454**	**-**	**FS**	**7,733**	**5,029**	**0.7**	**1.7**	**1.8**	**2,820**
2010 Total Residential	**26,400**	**2,020**	**967**	**2,987**	**130**	**3,117**	**96%**	**4%**	**33,830**	**32,333**	**8,867**	**-**	**12**	**2,348**	**8,101**	**2,741**	**356**	**5,883**	**250,428**	**62,315**	**-**	**0.8**	**967**	**8,980**	**9.3**	**0.4**	**3.4**	**7,332**
2008 - 2010 (NPV 2007)																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	4,251	850	215	1,065	0	1,065	100%	0%	35,283	31,755	106	-	3	3,285	142	4,555	554	77	345,662	1,093	-	3.1	-	5,185	N/A	0.6	3.2	2,362
EE E* Hot Water Saving Appliances	10,374	324	360	684	324	1,008	68%	32%	28,256	17,957	988	-	4	1,697	905	3,322	401	669	178,953	6,960	-	2.5	324	4,391	13.6	0.4	2.6	1,594
Subtotal New Constuction Energy Efficiency	**14,625**	**1,174**	**575**	**1,749**	**324**	**2,073**	**84%**	**16%**	**63,539**	**49,712**	**1,094**	**-**	**3**	**4,982**	**1,047**	**7,877**	**954**	**746**	**524,615**	**8,053**	**-**	**2.8**	**324**	**9,576**	**29.6**	**0.5**	**2.9**	**3,956**
FS Gas Cooking Range	10,431	522	363	885	(522)	363	244%	-144%	(97,009)	(55,295)	10,721	-	FS	(6,240)	9,895	(13,654)	(1,616)	8,461	(651,682)	76,118	-	FS	15,271	8,983	0.6	1.9	1.5	3,292
FS Gas Clothes Dryer	3,634	182	93	275	(182)	93	295%	-195%	(15,625)	(15,156)	3,230	-	FS	(1,719)	5,097	(2,210)	(262)	2,561	(179,468)	39,210	-	FS	2,472	2,743	1.1	1.1	2.8	3,285
Subtotal New Construction Fuel Substitution	**14,065**	**703**	**457**	**1,160**	**(703)**	**457**	**254%**	**-154%**	**(112,634)**	**(70,451)**	**13,951**	**-**	**FS**	**(7,959)**	**14,993**	**(15,864)**	**(1,879)**	**11,022**	**(831,150)**	**115,328**	**-**	**FS**	**17,743**	**11,726**	**0.7**	**1.7**	**1.8**	**6,577**
Retrofit																												
EE E* Furnace Upgrade	7,257	2,177	683	2,861	2,177	5,038	57%	43%	100,152	72,110	-	-	4	7,781	-	13,508	1,545	-	814,326	-	-	2.7	2,177	15,053	6.9	0.5	1.5	2,743
EE EnerChoice Fireplace	6,534	1,307	589	1,895	-	1,895	100%	0%	54,230	41,215	163	-	4	4,162	180	6,832	813	115	437,839	1,384	-	2.2	-	7,761	N/A	0.5	2.3	2,446
EE E* Hot Water Saving Appliances	15,589	585	453	1,038	585	1,623	64%	36%	45,988	30,812	2,591	-	3	2,940	2,413	5,465	657	1,755	309,852	18,559	-	2.8	585	7,877	13.5	0.5	3.3	3,730
Subtotal Retrofit Energy Efficiency	**29,380**	**4,069**	**1,725**	**5,794**	**2,762**	**8,556**	**68%**	**32%**	**200,371**	**144,137**	**2,755**	**-**	**4**	**14,882**	**2,593**	**25,804**	**3,015**	**1,870**	**1,562,017**	**19,943**	**-**	**2.6**	**2,762**	**30,690**	**11.1**	**0.5**	**2.0**	**8,919**
Subtotal Retrofit Fuel Substitution	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**N/A**	**-**	**-**	**N/A**	**N/A**	**N/A**	**N/A**
2008-2010 Subtotal Energy Efficiency	**44,005**	**5,243**	**2,300**	**7,543**	**3,086**	**10,629**	**71%**	**29%**	**263,910**	**193,849**	**3,849**	**-**	**4**	**19,864**	**3,639**	**33,681**	**3,969**	**2,616**	**2,086,632**	**27,996**	**-**	**2.6**	**3,086**	**40,267**	**13.0**	**0.5**	**2.2**	**12,875**
2008-2010 Subtotal Fuel Substitution	**14,065**	**703**	**457**	**1,160**	**-703**	**457**	**254%**	**-154%**	**(112,634)**	**(70,451)**	**13,951**	**-**	**FS**	**(7,959)**	**14,993**	**(15,864)**	**(1,879)**	**11,022**	**(831,150)**	**115,328**	**-**	**FS**	**17,743**	**11,726**	**0.7**	**1.7**	**1.8**	**6,577**
2008-2010 Total Residential	**58,070**	**5,946**	**2,757**	**8,703**	**2,382**	**11,085**	**79%**	**21%**	**151,276**	**123,398**	**17,800**	**-**	**7**	**11,905**	**18,632**	**17,817**	**2,091**	**13,638**	**1,255,482**	**143,324**	**-**	**1.4**	**2,382**	**33,546**	**14.1**	**0.4**	**2.8**	**19,452**

TERASEN GAS INC

		PROGRAM: COSTS ($000) – Utility							PROGRAM: SAVINGS (GJ)			LIFE	ALTERNATE: Impact		NET PRESENT VALUE: Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings			BENEFIT/COST	Participant					
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net-to-Gross	Net	Years	Energy MWh	Capacity kW	($/GJ)	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	Natural Gas Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label		B	C	D	E	F	G	H	Input (program)	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
Source Sheet or Calculation		Program	Program	B+C	Program	D+E	D/F	E/F	Program	Program	IxJ	Program	Program	Program	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2008																														
RESIDENTIAL:																														
New Construction																														
EE EnerChoice Fireplace	500	100	101	201	0	201	100%	0%	4,150	90%	3,735	15	13	-	6	330	14	455	51	8	34,566	109	-	1.6	-	514	N/A	0.5	1.7	143
EE E* Clothes Washers	500	25	94	119	25	144	83%	17%	1,700	67%	1,139	14	150	-	12	96	121	179	20	88	10,113	931	-	0.8	25	286	11.5	0.3	1.5	73
EE E* Dishwashers	2,000	50	40	90	50	140	64%	36%	5,000	62%	3,100	13	56	-	3	250	40	500	55	31	26,283	305	-	2.8	50	587	11.7	0.4	2.1	150
FS Gas Cooking Range	3,000	150	146	296	-150	146	203%	-103%	-27,900	57%	-15,903	18	3,083	-	FS	(1,562)	2,474	(3,414)	(379)	2,115	(162,921)	19,030	-	FS	3,792	2,265	0.6	1.8	1.4	766
FS Gas Clothes Dryer	900	45	18	63	-45	18	350%	-250%	-3,870	97%	-3,754	18	800	-	FS	(369)	1,092	(474)	(53)	549	(38,457)	8,402	-	FS	526	594	1.1	1.1	2.8	706
Retrofit																														
EE E* Furnace Upgrade	4,000	1,200	377	1,577	1,200	2,777	57%	43%	55,200	72%	39,744	18	-	-	4	3,903	N/A	6,754	749	N/A	407,163	-	-	2.5	1,200	7,503	6.3	0.5	1.4	1,126
EE EnerChoice Fireplace	2,000	400	224	624	0	624	100%	0%	16,600	76%	12,616	15	50	-	5	1,114	48	1,822	202	31	116,757	369	-	1.8	-	2,055	N/A	0.5	1.9	538
E* Dishwasher	2,000	50	104	154	50	204	76%	24%	5,000	67%	3,350	13	56	-	5	270	43	500	55	31	28,402	330	-	1.8	50	587	11.7	0.4	1.5	109
E* Clothes Washer	2,000	100	40	140	100	240	58%	42%	6,800	67%	4,556	14	609	-	3	386	493	714	79	359	40,454	3,795	-	2.8	100	1,152	11.5	0.5	3.7	639
2008																														
Total Residential	16,900	2,120	1,145	3,265	1,230	4,495	73%	27%	62,680		48,583		4,816	-	7	4,420	4,325	7,037	781	3,212	462,361	33,271	-	1.4	1,230	11,030	9.0	0.4	1.9	4,249
2009																														
RESIDENTIAL:																														
New Construction																														
EE EnerChoice Fireplace	1,500	300	41	341	0	341	100%	0%	12,450	90%	11,205	15	38	-	3	981	43	1,366	162	23	103,699	328	-	2.9	-	1,552	N/A	0.6	3.0	682
EE E* Clothes Washers	1,000	50	39	89	50	139	64%	36%	3,400	67%	2,278	14	299	-	4	191	242	357	43	176	20,227	1,863	-	2.1	50	576	11.5	0.4	3.1	294
EE E* Dishwashers	3,000	75	60	135	75	210	64%	36%	7,500	62%	4,650	13	83	-	3	372	59	750	90	47	39,424	457	-	2.8	75	887	11.8	0.4	2.1	221
FS Gas Cooking Range	4,000	200	111	311	-200	111	280%	-180%	-37,200	57%	-21,204	18	4,111	-	FS	(2,069)	3,298	(4,551)	(536)	2,820	(217,227)	25,373	-	FS	5,088	3,020	0.6	1.9	1.5	1,118
FS Gas Clothes Dryer	1,400	70	28	98	-70	28	350%	-250%	-6,020	97%	-5,839	18	1,244	-	FS	(570)	1,699	(737)	(87)	854	(59,823)	13,070	-	FS	823	924	1.1	1.1	2.8	1,101
Retrofit																														
EE E* Furnace Upgrade	4,000	1,200	377	1,577	1,200	2,777	57%	43%	55,200	72%	39,744	18	-	-	4	3,878	N/A	6,754	796	N/A	407,163	-	-	2.5	1,200	7,550	6.3	0.5	1.4	1,101
EE EnerChoice Fireplace	2,500	500	203	703	0	703	100%	0%	20,750	76%	15,770	15	63	-	5	1,380	60	2,277	270	38	145,946	461	-	2.0	-	2,586	N/A	0.5	2.0	737
E* Dishwasher	3,000	75	93	168	75	243	69%	31%	7,500	67%	5,025	13	83	-	4	402	64	750	90	47	42,604	494	-	2.4	75	887	11.8	0.4	1.9	223
E* Clothes Washer	3,000	150	60	210	150	360	58%	42%	10,200	67%	6,834	14	914	-	3	573	740	1,071	128	538	60,680	5,692	-	2.7	150	1,737	11.6	0.4	3.6	953
2009																														
Total Residential	23,400	2,620	1,013	3,633	1,280	4,913	74%	26%	73,780		58,463		6,835	-	7	5,138	6,206	8,038	955	4,544	542,693	47,738	-	1.4	1,280	13,537	10.6	0.4	2.3	6,431
2010																														
RESIDENTIAL:																														
New Construction																						-								
EE EnerChoice Fireplace	3,000	600	101	701	0	701	100%	0%	24,900	90%	22,410	15	75	-	3	1,975	85	2,733	341	46	207,397	656	-	2.8	-	3,120	N/A	0.6	2.9	1,358
EE E* Clothes Washers	1,500	75	74	149	75	224	67%	33%	5,100	67%	3,417	14	449	-	5	288	363	536	67	264	30,340	2,794	-	1.9	75	867	11.6	0.4	2.9	427
EE E* Dishwashers	4,000	100	105	205	100	305	67%	33%	10,000	62%	6,200	13	111	-	4	499	79	1,000	126	62	52,566	610	-	2.4	100	1,189	11.9	0.4	1.9	273
FS Gas Cooking Range	5,000	250	156	406	-250	156	260%	-160%	-46,500	57%	-26,505	18	5,139	-	FS	(2,610)	4,123	(5,689)	(701)	3,525	(271,534)	31,716	-	FS	6,390	3,775	0.6	1.9	1.5	1,357
FS Gas Clothes Dryer	1,900	95	63	158	-95	63	251%	-151%	-8,170	97%	-7,925	18	1,689	-	FS	(780)	2,306	(1,000)	(123)	1,159	(81,188)	17,738	-	FS	1,123	1,254	1.1	1.1	2.7	1,463
Retrofit																														
EE E* Furnace Upgrade	0	0	0	0	0	0	0%	0%	0%	0%	-	18	-	-	N/A	N/A	N/A	N/A	N/A	N/A	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE EnerChoice Fireplace	3,000	600	243	843	0	843	100%	0%	24,900	76%	18,924	15	75	-	5	1,667	72	2,733	341	46	175,135	554	-	2.0	-	3,120	N/A	0.5	2.1	896
E* Dishwasher	4,000	100	143	243	100	343	71%	29%	10,000	67%	6,700	13	111	-	4	539	86	1,000	126	62	56,805	659	-	2.2	100	1,189	11.9	0.4	1.8	282
E* Clothes Washer	4,000	200	80	280	200	480	58%	42%	13,600	67%	9,112	14	1,219	-	3	769	987	1,428	179	718	80,907	7,589	-	2.7	200	2,325	11.6	0.5	3.7	1,276
2010																														
Total Residential	26,400	2,020	967	2,987	130	3,117	96%	4%	33,830		32,333		8,867	-	12	2,348	8,101	2,741	356	5,883	250,428	62,315	-	0.8	130	8,980	69.1	0.4	3.4	7,332

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
3														
4			**Year**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
5			Units											
6		**NATURAL GAS**												
7		Incremental Cost of Gas (nominal)	$ Per GJ	$10.43	$9.02	$8.76	$8.61	$8.08	$9.27	$7.96	$8.41	$9.52	$9.23	$9.27
8	1		*Year*	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
9	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
10	3	Incremental Cost of Gas (Real)		$10.43	$9.02	$8.76	$8.61	$8.08	$9.27	$7.96	$8.41	$9.52	$9.23	$9.27
11	4	Net Present Value -2008			$17.69	$24.88	$31.52	$37.35	$43.61	$48.66	$53.64	$58.93	$63.74	$68.26
12	5	Net Present Value -2009				$16.14	$23.22	$29.44	$36.13	$41.51	$46.83	$52.48	$57.61	$62.44
13	6	Net Present Value -2010					$15.76	$22.40	$29.54	$35.29	$40.97	$47.00	$52.48	$57.63
14														
15														
16		**ELECTRICITY**												
17		Incremental Cost of Elec	$ Per kWh	$0.13										
18		Incremental Cost of E Capacity	$ Per kW	$170.00										
19														
20														
21														
22	**RETAIL**													
23				Rate	Customers		789,928	Total Customers in BC		80,000	Total Residential and Commercial Customers on VI			
24		Residential Retail			*000's*									
25		**TGI**	$ Per MJ	$0.0113	640		712,304	Total Residential Customers in BC						
26		**TGVI**	$ Per MJ	$0.0137	72									
27		**Electricity**	$ Per MJ	$0.0176										
28		**Electricity**	$ per kWh	$0.0634	1,511		1,511,435	Total BCH Residential Customers in BC				89%		
29		**Electricity**	$ per kW per year											
30		Commercial Retail												
31		**TGI**	$ Per MJ	$0.0107	78		77,624	Total Commercial Customers in BC						
32		**TGVI**	$ Per MJ	$0.0118	8									
33		**Electricity**	$ Per MJ	$0.0155										
34		**Electricity**	$ per kWh	$0.0558	190		189,764	Total Light Industrial and Commercial Customers in BC						
35		**Electricity**	$ per kW per year	$52	15									
36														
37	**TAX**													
38			**Year**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
39	1		*Year*		*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
40	2	Carbon	$ Per tonne		$10.00	$15.00	$20.00	$25.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
41	3	Carbon	$ Per GJ		$0.4988	$0.7482	$0.9976	$1.2470	$1.4964	$1.4964	$1.4964	$1.4964	$1.4964	$1.4964
42	4	GDP Deflator			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
43	5	Carbon (Real)			$0.50	$0.75	$1.00	$1.25	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
44	6	Net Present Value -2008				$1.12	$1.94	$2.90	$3.98	$5.00	$5.94	$6.83	$7.66	$8.44
45	7	Net Present Value -2009					$1.58	$2.60	$3.75	$4.83	$5.84	$6.79	$7.68	$8.51
46	8	Net Present Value -2010						$2.03	$3.26	$4.41	$5.49	$6.50	$7.45	$8.34
47														
48		**Discount Rate (real)[1]**												
49		**TERASEN GAS**												
50		**Rate of Inflation**	1.90%											
51		**TGI**	6.75%											
52		**TGVI**	6.38%											
53		**BC HYDRO**												
54		**Rate of Inflation**	2.00%											
55		**BC Hydro**	6.00%											
56		**Customer**	6.00%											
57		*Footnote 1: Source LR 070531*												

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for EE EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	8.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	10%	0.90			Net-to-Gross
Alternate Energy Impact	0.09	GJ		25	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	15	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			18,000	18,000	18,000	Information only
Participants	4,251	5,000	500	1,500	3,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	35,283	41,500	4,150	12,450	24,900	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	31,755	37,350	3,735	11,205	22,410	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	108,139	125,000	12,500	37,500	75,000	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$88.33	$87.51	$88.11	
Energy Purchases	$ 3,284,996	$ 3,284,996	$ 329,897	$ 980,596	$ 1,974,504	
Utility Program Costs						
DSM Incentives		$ 1,000,000	$ 100,000	$ 300,000	$ 600,000	
Administration		$ 243,999	$ 101,333	$ 41,333	$ 101,333	
Subtotal	$ 1,064,709	$ 1,243,999	$ 201,333	$ 341,333	$ 701,333	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 142,042	$ 14,204	$ 42,612	$ 85,225	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 142,042	$ 142,042	$ 14,204	$ 42,612	$ 85,225	
Net Benefit (Cost)	$ 2,362,328		$ 142,768	$ 681,875	$ 1,358,396	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.2**		**1.71**	**3.00**	**2.94**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.6**		**$ 5.8**	**$ 3.3**	**$ 3.4**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for EE E* Clothes Washers

PER MEASURE

Total Cost	$	100
Incentive	$	50
Participant	$	50

Annual Impact Per Measure

Energy Savings per installation	3.4	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0.33	0.67			Net-to-Gross
Alternate Energy Impact	1.0768	GJ		299	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	14	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			8600	8600	8600	Information only
Participants	2,579	3,000	500	1,000	1,500	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	8,769	10,200	1,700	3,400	5,100	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	5,875	6,834	1,139	2,278	3,417	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	784,007	897,333	149,556	299,111	448,667	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$83.86	$84.40	
Energy Purchases	$ 575,883	$ 575,883	$ 96,473	$ 191,029	$ 288,381	
Utility Program Costs						
DSM Incentives		$ 150,000	$ 25,000	$ 50,000	$ 75,000	
Administration		$ 207,999	$ 94,333	$ 39,333	$ 74,333	
Subtotal	$ 312,951	$ 357,999	$ 119,333	$ 89,333	$ 149,333	
Participants' Net Costs						
Incremental Cost		$ 150,000	$ 25,000	$ 50,000	$ 75,000	
Subtotal	$ 128,955	$ 150,000	$ 25,000	$ 50,000	$ 75,000	
Alternate Savings - Net						
Energy (Purchases)		$ 726,475	$ 121,079	$ 242,158	$ 363,237	$1.208 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 726,475	$ 726,475	$ 121,079	$ 242,158	$ 363,237	
Net Benefit (Cost)	$ 860,452		$73,220	$293,854	$427,285	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.95**		**1.51**	**3.11**	**2.90**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 8.5**		**$ 14.3**	**$ 6.9**	**$ 7.4**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for EE E* Dishwashers

PER MEASURE

Total Cost	$	50
Incentive	$	25
Participant	$	25

Annual Impact Per Measure

Energy Savings per installation	2.5	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0.38	0.62		Net-to-Gross
Alternate Energy Impact	0.1	GJ	28	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	13	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			15,500	15,500	15,500	Information only
Participants	7,795	9,000	2,000	3,000	4,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	19,487	22,500	5,000	7,500	10,000	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	12,082	13,950	3,100	4,650	6,200	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	219,868	250,000	55,556	83,333	111,111	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$80.68	$79.99	$80.49	
Energy Purchases	$ 1,121,109	$ 1,121,109	$ 250,108	$ 371,944	$ 499,058	
Utility Program Costs						
DSM Incentives		$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Administration		$ 205,000	$ 40,000	$ 60,000	$ 105,000	
Subtotal	$ 371,311	$ 430,000	$ 90,000	$ 135,000	$ 205,000	
Participants' Net Costs						
Incremental Cost		$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Subtotal	$ 194,866	$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Alternate Savings - Net						
Energy (Purchases)		$ 178,382	$ 39,640	$ 59,461	$ 79,281	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 178,382	$ 178,382	$ 39,640	$ 59,461	$ 79,281	
Net Benefit (Cost)	$ 733,313		$149,748	$221,404	$273,339	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.30**		**2.07**	**2.05**	**1.90**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.5**		**$ 5.3**	**$ 5.3**	**$ 5.8**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for FS Gas Cooking Range

PER MEASURE

Total Cost	$	-
Incentive	$	50
Participant	$	(50)

Annual Impact Per Measure

Energy Savings per installation	-9.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0.43	0.57			Net-to-Gross
Alternate Energy Impact	3.7	GJ		1,028	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			10,500	10,500	10,500	Information only
Participants	10,431	12,000	3,000	4,000	5,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-97,009	-111,600	-27,900	-37,200	-46,500	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-55,295	-63,612	-15,903	-21,204	-26,505	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	10,882,390	12,333,334	3,083,334	4,111,111	5,138,889	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$98.21	$97.57	$98.46	
Energy Purchases	$ (6,240,315)	$ (6,240,315)	$ (1,561,774)	$ (2,068,956)	$ (2,609,585)	
Utility Program Costs						
DSM Incentives		$ 600,000	$ 150,000	$ 200,000	$ 250,000	
Administration		$ 413,999	$ 146,333	$ 111,333	$ 156,333	
Subtotal	$ 884,860	$ 1,013,999	$ 296,333	$ 311,333	$ 406,333	
Participants' Net Costs						
Incremental Cost		$ (600,000)	$ (150,000)	$ (200,000)	$ (250,000)	
Subtotal	$ (521,555)	$ (600,000)	$ (150,000)	$ (200,000)	$ (250,000)	
Alternate Savings - Net						
Energy (Purchases)		$ 9,895,348	$ 2,473,837	$ 3,298,449	$ 4,123,062	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 9,895,348	$ 9,895,348	$ 2,473,837	$ 3,298,449	$ 4,123,062	
Net Benefit (Cost)	$ 3,291,728		$765,730	$1,118,161	$1,357,143	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**10.06**		**6.23**	**11.04**	**9.68**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for FS Gas Clothes Dryer

PER MEASURE

Total Cost	$	-
Incentive	$	50
Participant	$	(50)

Annual Impact Per Measure

Energy Savings per installation	-4.3	GJ		Average Annnual Energy Savings per Measure	
Free Rider Rate / Net-to-Gross	0.03	0.97		Net-to-Gross	
Alternate Energy Impact	3.2	GJ	889	kWh	
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			6,600	6,600	6,600	Information only
Participants	3,634	4,200	900	1,400	1,900	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-15,625	-18,060	-3,870	-6,020	-8,170	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-15,156	-17,518	-3,754	-5,839	-7,925	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	3,280,292	3,733,334	800,000	1,244,445	1,688,889	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$98.21	$97.57	$98.46	
Energy Purchases	$ (1,718,686)	$ (1,718,686)	$ (368,656)	$ (569,773)	$ (780,257)	
Utility Program Costs						
DSM Incentives		$ 210,000	$ 45,000	$ 70,000	$ 95,000	
Administration		$ 109,000	$ 18,000	$ 28,000	$ 63,000	
Subtotal	$ 274,910	$ 319,000	$ 63,000	$ 98,000	$ 158,000	
Participants' Net Costs						
Incremental Cost		$ (210,000)	$ (45,000)	$ (70,000)	$ (95,000)	
Subtotal	$ (181,684)	$ (210,000)	$ (45,000)	$ (70,000)	$ (95,000)	
Alternate Savings - Net						
Energy (Purchases)		$ 5,097,347	$ 1,092,289	$ 1,699,116	$ 2,305,943	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 5,097,347	$ 5,097,347	$ 1,092,289	$ 1,699,116	$ 2,305,943	
Net Benefit (Cost)	$ 3,285,436		$705,632	$1,101,343	$1,462,686	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**36.24**		**40.20**	**40.33**	**24.22**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
RETROFIT

Measure Data for EE E* Furnace Upgrade

PER MEASURE

Total Cost	$	600
Incentive	$	300
Participant	$	300

Annual Impact Per Measure

Energy Savings per installation	13.8	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0.28	0.72		Net-to-Gross
Alternate Energy Impact	0.0	GJ	0	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	18	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			18,500	18,500	18,500	Information only
Participants	7,257	8,000	4,000	4,000	0	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	100,152	110,400	55,200	55,200	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	72,110	79,488	39,744	39,744	0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	0	0	0	0	0	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$98.21	$97.57	$98.46	
Energy Purchases	$ 7,781,083	$ 7,781,083	$ 3,903,109	$ 3,877,974	$ -	
Utility Program Costs						
DSM Incentives		$ 2,400,000	$ 1,200,000	$ 1,200,000	$ -	
Administration		$ 753,332	$ 376,666	$ 376,666	$ -	
Subtotal	$ 2,860,629	$ 3,153,332	$ 1,576,666	$ 1,576,666	$ -	
Participants' Net Costs						
Incremental Cost		$ 2,400,000	$ 1,200,000	$ 1,200,000	$ -	
Subtotal	$ 2,177,224	$ 2,400,000	$ 1,200,000	$ 1,200,000	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Benefit (Cost)	$ 2,743,231		$1,126,443	$1,101,308	$0	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.54**		**1.41**	**1.40**	**-**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 6.8**		**$ 6.8**	**$ 6.8**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
RETROFIT

Measure Data for EE EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	8.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0.24	0.76			Net-to-Gross
Alternate Energy Impact	0.09	GJ		25	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	15	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			6,000	6,000	6,000	Information only
Participants	6,534	7,500	2,000	2,500	3,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	54,230	62,250	16,600	20,750	24,900	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	41,215	47,310	12,616	15,770	18,924	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	165,766	187,500	50,000	62,500	75,000	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$88.33	$87.51	$88.11	
Energy Purchases	$ 4,161,774	$ 4,161,774	$ 1,114,317	$ 1,380,097	$ 1,667,359	
Utility Program Costs						
DSM Incentives		$ 1,500,000	$ 400,000	$ 500,000	$ 600,000	
Administration		$ 670,999	$ 224,333	$ 203,333	$ 243,333	
Subtotal	$ 1,895,386	$ 2,170,999	$ 624,333	$ 703,333	$ 843,333	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 179,919	$ 47,979	$ 59,973	$ 71,968	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 179,919	$ 179,919	$ 47,979	$ 59,973	$ 71,968	
Net Benefit (Cost)	$ 2,446,307		$537,963	$736,738	$895,994	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.29**		**1.86**	**2.05**	**2.06**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.0**		**$ 5.3**	**$ 4.8**	**$ 4.8**	Informational (for comparison with supply options)

TERASEN GAS INC

RESIDENTIAL

RETROFIT

Measure Data for E* Dishwasher

PER MEASURE

Total Cost	$	50
Incentive	$	25
Participant	$	25

Annual Impact Per Measure

Energy Savings per installation	2.5	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0.33	0.67		Net-to-Gross
Alternate Energy Impact	0.1	GJ	28	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	13	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			44,000	44,000	44,000	Information only
Participants	7,795	9,000	2,000	3,000	4,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	19,487	22,500	5,000	7,500	10,000	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	13,056	15,075	3,350	5,025	6,700	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	219,868	250,000	55,556	83,333	111,111	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$80.68	$79.99	$80.49	
Energy Purchases	$ 1,211,521	$ 1,211,521	$ 270,278	$ 401,939	$ 539,305	
Utility Program Costs						
DSM Incentives		$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Administration		$ 340,999	$ 104,333	$ 93,333	$ 143,333	
Subtotal	$ 492,343	$ 565,999	$ 154,333	$ 168,333	$ 243,333	
Participants' Net Costs						
Incremental Cost		$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Subtotal	$ 194,866	$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Alternate Savings - Net						
Energy (Purchases)		$ 192,767	$ 42,837	$ 64,256	$ 85,674	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 192,767	$ 192,767	$ 42,837	$ 64,256	$ 85,674	
Net Benefit (Cost)	$ 717,080		$108,782	$222,862	$281,646	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.04**		**1.53**	**1.92**	**1.82**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 6.2**		**$ 7.2**	**$ 5.7**	**$ 6.0**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
RETROFIT

Measure Data for E* Clothes Washer

PER MEASURE

Total Cost	$ 100				
Incentive	**$ 50**				
Participant	**$ 50**				
Annual Impact Per Measure					
Energy Savings per installation	**3.4**	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	**0.33**	0.67			Net-to-Gross
Alternate Energy Impact	**1.0968**	GJ		305	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	**14**	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			**40,000**	**40,000**	**40,000**	Information only
Participants	7,795	9,000	**2,000**	**3,000**	**4,000**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	26,502	30,600	6,800	10,200	13,600	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	17,756	20,502	4,556	6,834	9,112	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	2,411,516	2,742,000	609,333	914,000	1,218,667	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

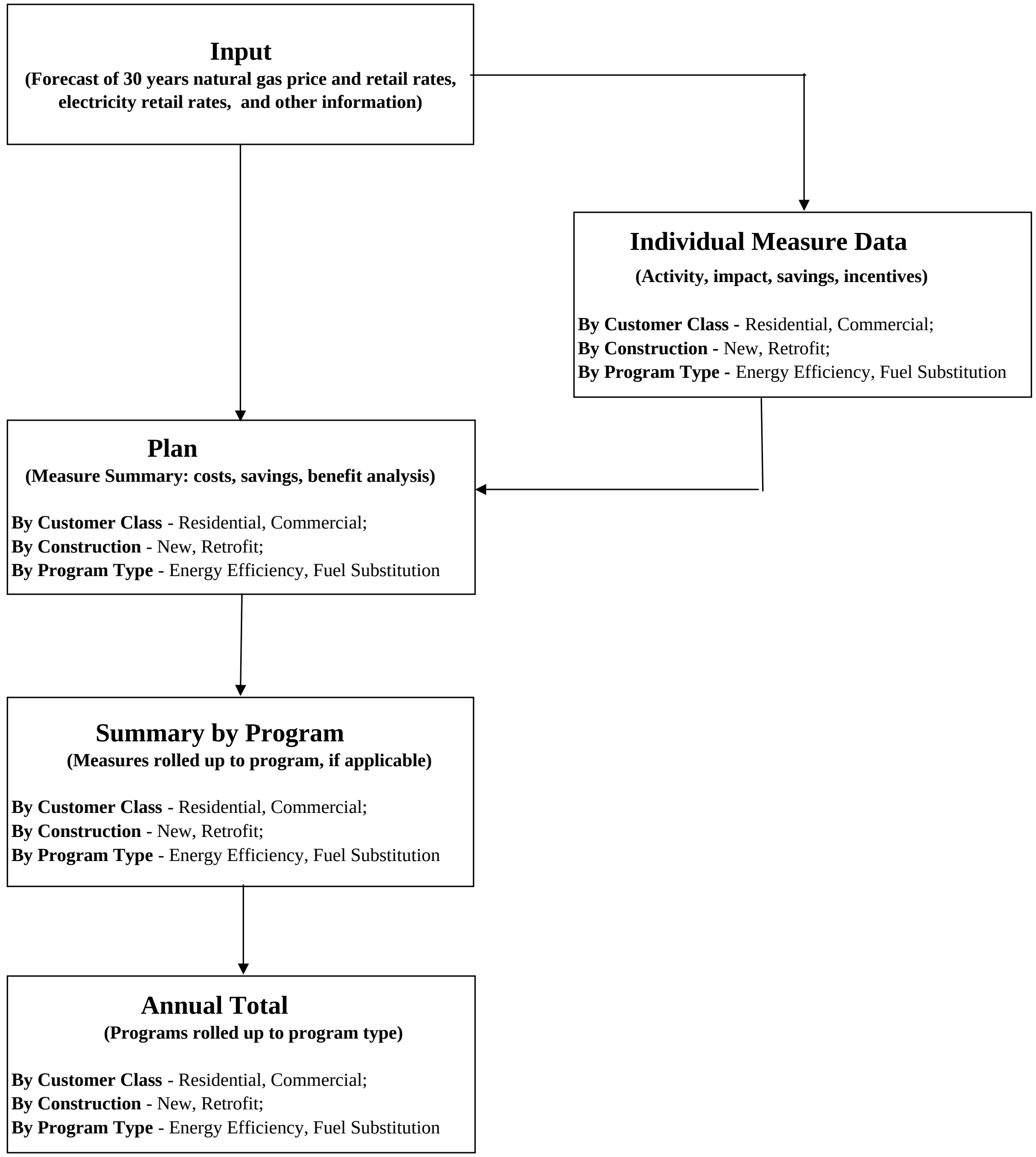
Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$83.86	$84.40	
Energy Purchases	$ 1,727,996	$ 1,727,996	$ 385,894	$ 573,087	$ 769,015	
Utility Program Costs						
DSM Incentives		$ 450,000	$ 100,000	$ 150,000	$ 200,000	
Administration		$ 180,000	**$ 40,000**	**$ 60,000**	**$ 80,000**	
Subtotal	$ 545,625	$ 630,000	$ 140,000	$ 210,000	$ 280,000	
Participants' Net Costs						
Incremental Cost		$ 450,000	$ 100,000	$ 150,000	$ 200,000	
Subtotal	$ 389,732	$ 450,000	$ 100,000	$ 150,000	$ 200,000	
Alternate Savings - Net						
Energy (Purchases)		$ 2,219,904	$ 493,312	$ 739,968	$ 986,624	$1.208 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 2,219,904	$ 2,219,904	$ 493,312	$ 739,968	$ 986,624	
Net Benefit (Cost)	$ 3,012,543		$639,206	$953,055	$1,275,639	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.22**		**3.66**	**3.65**	**3.66**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.9**		**$ 5.9**	**$ 5.9**	**$ 5.9**	Informational (for comparison with supply options)

Table of Contents

Sheet Name	Description	MEASURE_NAME
Annual Total	Program Type Summary - costs, savings, and benefit analysis	
Summary by Program	Program Summary - costs, savings, and benefit analysis - annual and total	
Plan	Measures Summary - costs, savings, and benefit analysis - annual	
Input	30 years Natural Gas Price, and other inputs to the model	
EEbldg 30% Large	Measure data and benefit analysis for Efficient Design - 30% Large (New Construction)	EE Building Design (30% Large)
EEbldg 30% Small	Measure data and benefit analysis for Efficient Design - 30% Small (New Construction)	EE Building Design (30% Small)
EEbldg 60%	Measure data and benefit analysis for Efficient Design - 60% (New Construction)	EE Building Design (60%)
HP Glazing Hit	Measure data and benefit analysis for HIT Windows (New Construction)	High Performance Glazing HIT
NearCond Boilers	Measure data and benefit analysis for Near Condensing Boilers (New Construction)	Near Condensing Boiler
Cond Boilers	Measure data and benefit analysis for Condensing Boilers (New Construction)	Condensing Boiler
Inst DHW Heaters	Measure data and benefit analysis for Instantaneous DHW Heaters (New Construction)	Instantaneous DHW Heater
Cond DHW Boilers	Measure data and benefit analysis for Condensing DHW Boilers (New Construction)	Condensing DHW Boiler
Cond DHW Heaters	Measure data and benefit analysis for Condensing DHW Heaters (New Construction)	Condensing DHW Heater
Drainwater Heat Rec	Measure data and benefit analysis for Drainwater Heat Recovery (New Construction)	Drainwater Heat Recovery
Retrofit NearCondBoilers	Measure data and benefit analysis for Near Condensing Boilers (Retrofit)	Near Condensing Boiler
Retrofit CondBoilers	Measure data and benefit analysis for Condensing Boilers (Retrofit)	Condensing Boiler
Retrofit Bldg Re-Comm	Measure data and benefit analysis for Building Recommissioning (Retrofit)	Building Recommissioning
Retrofit NextGenBAS	Measure data and benefit analysis for Next Generation BAS (Retrofit)	Next Generation Building Automation System
Retrofit HE Roof Top	Measure data and benefit analysis for HE Rooftop units (Retrofit)	High Efficiency Roof Top Unit
Retrofit Inst DHW Heaters	Measure data and benefit analysis for Instantaneous DHW Heaters (Retrofit)	Instantaneous DHW Heaters
Retrofit Cond DHW Boilers	Measure data and benefit analysis for Condensing DHW Boilers (Retrofit)	Condensing DHW Boiler
Retrofit Cond DHW Heaters	Measure data and benefit analysis for Condensing DHW Heaters (Retrofit)	Condensing DHW Heater

PROGRAM NAME
Efficient New Construction
Efficient New Construction
Efficient New Construction
Efficient New Construction
Boilers
Boilers
Water Heating
Water Heating
Water Heating
Water Heating
Boilers
Boilers
Building Recommissioning
Next Generation Building Automation System
High Efficiency Roof Top Unit
Water Heating
Water Heating
Water Heating


Input
(Forecast of 30 years natural gas price and retail rates, electricity retail rates, and other information)
Individual Measure Data
(Activity, impact, savings, incentives)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Plan
(Measure Summary: costs, savings, benefit analysis)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Summary by Program
(Measures rolled up to program, if applicable)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Annual Total
(Programs rolled up to program type)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution

TERASEN GAS VANCOUVER ISLAND

		PROGRAM									ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings				Participant					
		Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas				Natural Gas		TRC Net Benefits
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Rate Impact	Total Resource	($'000s)
2008																												
COMMERCIAL:																												
New Construction	7	73	16	89	73	163	55%	45%	3,689	3,343	-	-	2	380	-	537	59	-	39,800	-	-	4.2	73	596	8.1	0.6	2.3	217
Retrofit	17	308	95	403	308	711	57%	43%	14,121	12,161	900	-	3	1,325	818	1,986	218	370	139,120	6,293	-	3.3	308	2,573	8.4	0.6	3.0	1,433
2008 Total Commercial	**24**	**381**	**111**	**492**	**381**	**873**	**56%**	**44%**	**17,810**	**15,504**	**900**	**-**	**3**	**1,705**	**818**	**2,524**	**276**	**370**	**178,920**	**6,293**	**-**	**3.5**	**381**	**3,170**	**8.3**	**0.6**	**2.9**	**1,650**
2009																												
COMMERCIAL:																												
New Construction	8	74	15	90	74	164	55%	45%	3,763	3,405	-	-	2	384	-	546	63	-	40,389	-	-	4.3	74	609	8.2	0.6	2.3	220
Retrofit	27	474	121	595	474	1,069	56%	44%	20,371	17,798	1,125	-	3	1,942	1,023	2,877	333	462	204,712	7,866	-	3.3	474	3,671	7.7	0.6	2.8	1,896
2009 Total Commercial	**35**	**548**	**136**	**684**	**548**	**1,233**	**56%**	**44%**	**24,133**	**21,202**	**1,125**	**-**	**3**	**2,326**	**1,023**	**3,423**	**396**	**462**	**245,101**	**7,866**	**-**	**3.4**	**548**	**4,280**	**7.8**	**0.6**	**2.7**	**2,116**
2010																												
COMMERCIAL:																												
New Construction	17	798	78	876	886	1,761	50%	50%	11,767	10,938	3,044	-	7	1,270	4,806	1,737	208	2,171	132,049	36,967	-	1.5	886	4,117	4.6	0.5	3.4	4,314
Retrofit	37	625	171	796	625	1,421	56%	44%	27,667	24,498	2,025	-	3	2,637	1,841	3,833	462	832	276,486	14,159	-	3.3	625	5,127	8.2	0.6	3.2	3,057
2010 Total Commercial	**54**	**1,422**	**249**	**1,671**	**1,511**	**3,182**	**53%**	**47%**	**39,434**	**35,436**	**5,069**	**-**	**4**	**3,907**	**6,646**	**5,570**	**670**	**3,003**	**408,535**	**51,125**	**-**	**2.3**	**1,511**	**9,243**	**6.1**	**0.5**	**3.3**	**7,372**
2008 - 2010 (NPV 2007)																												
COMMERCIAL:																												
New Construction	28	797	94	891	870	1,761	51%	49%	16,567	15,237	2,528	-	4	2,034	4,806	2,820	330	2,171	212,238	36,967	-	2.3	870	5,322	6.1	0.5	3.9	5,078
Retrofit	71	1,227	338	1,565	1,227	2,792	56%	44%	54,256	47,508	3,522	-	3	5,905	3,681	8,696	1,012	1,663	620,318	28,318	-	3.8	1,227	11,372	9.3	0.6	3.4	6,793
2008 - 2010 Total Commercial	**98**	**2,024**	**431**	**2,456**	**2,098**	**4,553**	**54%**	**46%**	**70,823**	**62,745**	**6,051**	**-**	**3**	**7,938**	**8,487**	**11,516**	**1,342**	**3,835**	**832,556**	**65,284**	**-**	**3.2**	**2,098**	**16,693**	**8.0**	**0.6**	**3.6**	**11,872**

TERASEN GAS VANCOUVER ISLAND		PROGRAM									ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings				Participant					
		Utility									Energy	Capacity	($/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
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2008																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Boilers	2	53	11	64	53	117	55%	45%	1,754	1,438	-	-	4	170	-	265	29	-	17,740	-	-	2.7	53	294	5.6	0.5	1.5	53
Water Heating	5	20	5	25	20	46	56%	44%	1,935	1,904	-	-	1	210	-	273	30	-	22,059	-	-	8.3	20	303	14.9	0.7	4.6	164
Subtotal New Constuction	**7**	**73**	**16**	**89**	**73**	**163**	**55%**	**45%**	**3,689**	**3,343**	**-**	-	2	**380**	**-**	**537**	**59**	**-**	**39,800**	**-**	-	**4.2**	**73**	**596**	**8.1**	**0.6**	**2.3**	**217**
Retrofit																												
Boilers	9	223	33	256	223	478	53%	47%	9,333	7,620	-	-	3	902	-	1,408	154	-	93,985	-	-	3.5	223	1,562	7.0	0.5	1.9	424
Building Recommissioning	2	64	26	90	64	154	58%	42%	1,950	1,853	900	-	7	120	818	169	18	370	13,392	6,293	-	1.3	64	557	8.7	0.5	6.1	784
Next Generation Building Automa	-	-	1	1	-	1	100%	0%	-	-	-	-	LB	-	-	-	-	-	-	-	-	LB	-	-	N/A	N/A	LB	LB
High Efficiency Roof Top Unit	-	-	1	1	-	1	100%	0%	-	-	-	-	LB	-	-	-	-	-	-	-	-	LB	-	-	N/A	N/A	LB	LB
Water Heating	6	21	34	55	21	76	72%	28%	2,838	2,689	-	-	2	303	-	409	45	-	31,742	-	-	5.5	21	454	21.5	0.7	4.0	227
Subtotal Retrofit	**17**	**308**	**95**	**403**	**308**	**711**	**57%**	**43%**	**14,121**	**12,161**	**900**	-	3	**1,325**	**818**	**1,986**	**218**	**370**	**139,120**	**6,293**	-	**3.3**	**308**	**2,573**	**8.4**	**0.6**	**3.0**	**1,433**
2008 Total Commercial	**24**	**381**	**111**	**492**	**381**	**873**	**56%**	**44%**	**17,810**	**15,504**	**900**	-	3	**1,705**	**818**	**2,524**	**276**	**370**	**178,920**	**6,293**	-	**3.5**	**381**	**3,170**	**8.3**	**0.6**	**2.9**	**1,650**
2009																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Boilers	2	53	9	62	53	115	54%	46%	1,754	1,438	-	-	4	170	-	265	31	-	17,740	-	-	2.7	53	295	5.6	0.5	1.5	55
Water Heating	6	21	6	27	21	49	56%	44%	2,009	1,967	-	-	1	214	-	281	33	-	22,649	-	-	7.8	21	314	14.7	0.7	4.4	165
Subtotal New Constuction	**8**	**74**	**15**	**90**	**74**	**164**	**55%**	**45%**	**3,763**	**3,405**	**-**	-	2	**384**	**-**	**546**	**63**	**-**	**40,389**	**-**	-	**4.3**	**74**	**609**	**8.2**	**0.6**	**2.3**	**220**
Retrofit																												
Boilers	12	332	41	373	332	705	53%	47%	13,374	11,159	-	-	3	1,317	-	2,017	233	-	137,642	-	-	3.5	332	2,250	6.8	0.6	1.9	612
Building Recommissioning	2	64	26	90	64	154	58%	42%	1,950	1,853	900	-	7	118	818	169	20	370	13,392	6,293	-	1.3	64	559	8.7	0.5	6.1	782
Next Generation Building Automa	1	40	7	47	40	87	54%	46%	487	463	225	-	14	29	205	42	5	92	3,345	1,573	-	0.6	40	140	3.5	0.3	2.7	147
High Efficiency Roof Top Unit	1	5	3	8	5	12	63%	37%	122	122	-	-	6	13	-	16	2	-	1,355	-	-	1.7	5	18	4.1	0.5	1.1	1
Water Heating	11	34	43	77	34	111	70%	30%	4,438	4,201	-	-	2	465	-	631	73	-	48,978	-	-	6.0	34	704	20.9	0.7	4.2	355
Subtotal Retrofit	**27**	**474**	**121**	**595**	**474**	**1,069**	**56%**	**44%**	**20,371**	**17,798**	**1,125**	-	3	**1,942**	**1,023**	**2,877**	**333**	**462**	**204,712**	**7,866**	-	**3.3**	**474**	**3,671**	**7.7**	**0.6**	**2.8**	**1,896**
2009 Total Commercial	**35**	**548**	**136**	**684**	**548**	**1,233**	**56%**	**44%**	**24,133**	**21,202**	**1,125**	-	3	**2,326**	**1,023**	**3,423**	**396**	**462**	**245,101**	**7,866**	-	**3.4**	**548**	**4,280**	**7.8**	**0.6**	**2.7**	**2,116**
2010																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	4	669	57	727	758	1,484	49%	51%	5,029	4,777	3,044	-	12	569	4,806	759	91	2,171	58,923	36,967	-	0.8	758	3,021	4.0	0.4	3.6	3,890
Boilers	3	88	10	98	88	185	53%	47%	2,868	2,352	-	-	3	280	-	433	52	-	29,008	-	-	2.9	88	484	5.5	0.5	1.5	95
Water Heating	10	41	10	51	41	91	56%	44%	3,871	3,809	-	-	1	421	-	546	66	-	44,118	-	-	8.3	41	611	15.0	0.7	4.6	330
Subtotal New Constuction	**17**	**798**	**78**	**876**	**886**	**1,761**	**50%**	**50%**	**11,767**	**10,938**	**3,044**	-	7	**1,270**	**4,806**	**1,737**	**208**	**2,171**	**132,049**	**36,967**	-	**1.5**	**886**	**4,117**	**4.6**	**0.5**	**3.4**	**4,314**
Retrofit																												
Boilers	14	398	47	445	398	842	53%	47%	15,882	13,319	-	-	3	1,586	-	2,396	287	-	164,281	-	-	3.6	398	2,683	6.7	0.6	1.9	744
Building Recommissioning	4	128	46	174	128	302	58%	42%	3,900	3,705	1,800	-	7	236	1,636	339	42	739	26,785	12,586	-	1.4	128	1,120	8.8	0.5	6.2	1,569
Next Generation Building Automa	1	40	7	47	40	87	54%	46%	487	463	225	-	14	29	205	42	5	92	3,345	1,573	-	0.6	40	140	3.5	0.3	2.7	147
High Efficiency Roof Top Unit	1	5	3	8	5	12	63%	37%	122	122	-	-	6	13	-	16	2	-	1,355	-	-	1.7	5	18	4.1	0.5	1.1	1
Water Heating	17	55	67	122	55	177	69%	31%	7,276	6,890	-	-	2	773	-	1,040	125	-	80,721	-	-	6.3	55	1,165	21.3	0.7	4.4	597
Subtotal Retrofit	**37**	**625**	**171**	**796**	**625**	**1,421**	**56%**	**44%**	**27,667**	**24,498**	**2,025**	-	3	**2,637**	**1,841**	**3,833**	**462**	**832**	**276,486**	**14,159**	-	**3.3**	**625**	**5,127**	**8.2**	**0.6**	**3.2**	**3,057**
2010 Total Commercial	**54**	**1,422**	**249**	**1,671**	**1,511**	**3,182**	**53%**	**47%**	**39,434**	**35,436**	**5,069**	-	4	**3,907**	**6,646**	**5,570**	**670**	**3,003**	**408,535**	**51,125**	-	**2.3**	**1,511**	**9,243**	**6.1**	**0.5**	**3.3**	**7,372**
2008 - 2010 (NPV 2007)																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	3	556	48	604	629	1,233	49%	51%	4,177	3,968	2,528	-	10	569	4,806	759	91	2,171	58,923	36,967	-	0.9	629	3,021	4.8	0.4	4.4	4,141
Boilers	6	169	27	197	169	366	54%	46%	5,581	4,576	-	-	3	620	-	962	111	-	64,489	-	-	3.2	169	1,073	6.3	0.5	1.7	254
Water Heating	18	72	18	90	72	162	56%	44%	6,809	6,692	-	-	1	845	-	1,100	128	-	88,826	-	-	9.4	72	1,228	17.1	0.7	5.2	683
Subtotal New Constuction	**28**	**797**	**94**	**891**	**870**	**1,761**	**51%**	**49%**	**16,567**	**15,237**	**2,528**	-	4	**2,034**	**4,806**	**2,820**	**330**	**2,171**	**212,238**	**36,967**	-	**2.3**	**870**	**5,322**	**6.1**	**0.5**	**3.9**	**5,078**
Retrofit																												
Boilers	31	833	106	939	833	1,772	53%	47%	33,784	28,087	-	-	2	3,805	-	5,821	674	-	395,908	-	-	4.1	833	6,495	7.8	0.6	2.1	2,033
Building Recommissioning	7	223	86	309	223	532	58%	42%	6,796	6,456	3,136	-	6	473	3,272	677	81	1,478	53,570	25,171	-	1.5	223	2,237	10.0	0.5	7.0	3,213
Next Generation Building Automa	2	69	13	82	69	150	54%	46%	835	793	386	-	12	59	409	85	10	185	6,689	3,146	-	0.7	69	280	4.1	0.4	3.1	318
High Efficiency Roof Top Unit	2	8	6	14	8	22	64%	36%	209	209	-	-	5	25	-	33	4	-	2,710	-	-	1.8	8	37	4.8	0.5	1.2	4
Water Heating	29	95	126	221	95	316	70%	30%	12,633	11,964	-	-	1	1,542	-	2,080	243	-	161,441	-	-	7.0	95	2,323	24.4	0.7	4.9	1,226
Subtotal Retrofit	**71**	**1,227**	**338**	**1,565**	**1,227**	**2,792**	**56%**	**44%**	**54,256**	**47,508**	**3,522**	-	3	**5,905**	**3,681**	**8,696**	**1,012**	**1,663**	**620,318**	**28,318**	-	**3.8**	**1,227**	**11,372**	**9.3**	**0.6**	**3.4**	**6,793**
2008 - 2010 Total Commercial	**98**	**2,024**	**431**	**2,456**	**2,098**	**4,553**	**54%**	**46%**	**70,823**	**62,745**	**6,051**	-	**3**	**7,938**	**8,487**	**11,516**	**1,342**	**3,835**	**832,556**	**65,284**	-	**3.2**	**2,098**	**16,693**	**8.0**	**0.6**	**3.6**	**11,872**

TERASEN GAS VANCOUVER ISLAND

		PROGRAM											ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)			LIFE	Impact		Levelized Cost	Utility Benefits		Participant Benefits (Costs)			Program Net Savings				Participant					
		Utility										Years	Energy	Capacity	($/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
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net-to-Gross	Net		MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label		B	C	D	E	F	G	H	Input (program)	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
Source Sheet or Calculation		Program	Program	B+C	Program	D+E	D/F	E/F	Program	Program	IxJ	Program	Program	Program	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2008																														
COMMERCIAL:																														
New Construction																														
EE Building Design (30% Large)	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE Building Design (30% Small)	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE Building Design (60%)	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
High Performance Glazing HIT	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Near Condensing Boiler	1	18	9	27	18	46	60%	40%	640	82%	525	25	-	-	7	62	N/A	97	10.6	N/A	6,473	-	-	2.3	18	107	5.9	0.5	1.4	16
Condensing Boiler	1	35	2	37	35	71	51%	49%	1,114	82%	913	25	-	-	6	108	N/A	168	18.4	N/A	11,267	-	-	2.9	35	186	5.4	0.5	1.5	37
Instantaneous DHW Heater	2	2	2	4	2	6	63%	37%	146	85%	124	15	-	-	5	11	N/A	17	1.8	N/A	1,179	-	-	3.0	2	19	8.9	0.5	1.9	5
Condensing DHW Boiler	1	9	1	10	9	18	53%	47%	1,238	100%	1,238	25	-	-	1	147	N/A	187	20.5	N/A	15,270	-	-	15.4	9	207	24.4	0.7	8.1	129
Condensing DHW Heater	1	1	1	2	1	3	67%	33%	108	100%	108	10	-	-	4	7	N/A	9	1.0	N/A	779	-	-	3.5	1	10	10.4	0.6	2.3	4
Drainwater Heat Recovery	1	9	2	10	9	19	54%	46%	443	98%	434	20	-	-	4	45	N/A	60	6.6	N/A	4,831	-	-	4.4	9	67	7.6	0.6	2.4	26
Retrofit																														
Near Condensing Boiler	8	180	29	208	180	388	54%	46%	7,800	80%	6,240	25	-	-	5	739	N/A	1,177	129.1	N/A	76,967	-	-	3.5	180	1,306	7.3	0.5	1.9	351
Condensing Boiler	1	43	4	47	43	91	52%	48%	1,533	90%	1,380	25	-	-	5	163	N/A	231	25.4	N/A	17,018	-	-	3.5	43	257	5.9	0.6	1.8	73
Building Recommissioning	2	64	26	90	64	154	58%	42%	1,950	95%	1,853	10	900	-	12	120	818	169	18.3	370	13,392	6,293	-	1.3	64	557	8.7	0.5	6.1	784
Next Generation Building Automation System	-	-	1	1	-	1	100%	-	0	95%	0	10	-	-	LB	LB	N/A	LB	-	N/A	-	-	-	LB	-	-	N/A	N/A	LB	LB
High Efficiency Roof Top Unit	-	-	1	1	-	1	100%	-	0	100%	0	20	-	-	LB	LB	N/A	LB	-	N/A	-	-	-	LB	-	-	N/A	N/A	LB	LB
Instantaneous DHW Heaters	2	2	22	24	2	26	92%	8%	146	90%	132	15	-	-	21	11	N/A	17	1.8	N/A	1,249	-	-	0.5	2	19	8.9	0.3	0.4	(15)
Condensing DHW Boiler	2	17	6	23	17	40	58%	43%	2,476	95%	2,352	25	-	-	1	278	N/A	373	41.0	N/A	29,013	-	-	12.1	17	414	24.4	0.7	7.0	238
Condensing DHW Heater	2	2	6	8	2	10	80%	20%	216	95%	205	10	-	-	7	13	N/A	19	2.0	N/A	1,481	-	-	1.7	2	21	10.4	0.5	1.3	3
2008																														
Total Commercial	24	381	111	492	381	873			17,810		15,504		900	-	5	1,705	818	2,524	276	370	178,920	6,293	-	3.5	381	3,170	8.3	0.6	2.9	1,650
2009																														
COMMERCIAL:																														
New Construction																														
EE Building Design (30% Large)	-	-	-	-	-	-	-	-	0	95%	0	25	-	-	- -	-		-	-	- -		-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE Building Design (30% Small)	-	-	-	-	-	-	-	-	0	95%	0	25	-	-	- -	-		-	-	- -		-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE Building Design (60%)	-	-	-	-	-	-	-	-	0	95%	0	25	-	-	- -	-		-	-	- -		-	-	N/A	-	-	N/A	N/A	N/A	N/A
High Performance Glazing HIT	-	-	-	-	-	-	-	-	0	95%	0	25	-	-	- -	-		-	-	- -		-	-	N/A	-	-	N/A	N/A	N/A	N/A
Near Condensing Boiler	1	18	7	26	18	44	58%	42%	640	82%	525	25	-	-	7	62	N/A	97	11.1	N/A	6,473	-	-	2.4	18	108	5.9	0.5	1.4	18
Condensing Boiler	1	35	2	37	35	71	51%	49%	1,114	82%	913	25	-	-	6	108	N/A	168	19.4	N/A	11,267	-	-	2.9	35	187	5.4	0.5	1.5	37
Instantaneous DHW Heater	3	3	3	6	3	9	64%	36%	220	85%	187	15	-	-	5	16	N/A	25	2.9	N/A	1,769	-	-	2.8	3	28	8.9	0.5	1.8	7
Condensing DHW Boiler	1	9	1	10	9	18	53%	47%	1,238	100%	1,238	25	-	-	1	146	N/A	187	21.5	N/A	15,270	-	-	15.4	9	208	24.5	0.7	8.1	128
Condensing DHW Heater	1	1	1	2	1	3	67%	33%	108	100%	108	10	-	-	4	7	N/A	9	1.1	N/A	779	-	-	3.4	1	10	10.5	0.6	2.3	4
Drainwater Heat Recovery	1	9	2	10	9	19	54%	46%	443	98%	434	20	-	-	4	45	N/A	60	7.0	N/A	4,831	-	-	4.4	9	67	7.6	0.6	2.4	26
Retrofit																														
Near Condensing Boiler	9	202	29	231	202	433	53%	47%	8,775	80%	7,020	25	-	-	5	829	N/A	1,324	152.7	N/A	86,588	-	-	3.6	202	1,476	7.3	0.5	1.9	396
Condensing Boiler	3	130	12	142	130	272	52%	48%	4,599	90%	4,139	25	-	-	5	489	N/A	694	80.0	N/A	51,054	-	-	3.4	130	774	6.0	0.6	1.8	217
Building Recommissioning	2	64	26	90	64	154	58%	42%	1,950	95%	1,853	10	900	-	12	118	818	169	19.9	370	13,392	6,293	-	1.3	64	559	8.7	0.5	6.1	782
Next Generation Building Automation System	1	40	7	47	40	87	54%	46%	487	95%	463	10	225	-	26	29	205	42	5.0	92	3,345	1,573	-	0.6	40	140	3.5	0.3	2.7	147
High Efficiency Roof Top Unit	1	5	3	8	5	12	63%	37%	122	100%	122	20	-	-	9	13	N/A	16	1.9	N/A	1,355	-	-	1.7	5	18	4.1	0.5	1.1	1
Instantaneous DHW Heaters	4	4	22	26	4	31	86%	14%	293	90%	264	15	-	-	12	23	N/A	34	3.9	N/A	2,497	-	-	0.9	4	37	8.9	0.4	0.7	(8)
Condensing DHW Boiler	3	26	9	35	26	60	58%	43%	3,714	95%	3,528	25	-	-	1	416	N/A	560	64.6	N/A	43,520	-	-	12.1	26	625	24.5	0.7	6.9	356
Condensing DHW Heater	4	4	12	16	4	20	80%	20%	431	95%	410	10	-	-	7	26	N/A	37	4.4	N/A	2,961	-	-	1.6	4	42	10.5	0.5	1.3	6
2009																														
Total Commercial	35	548	136	684	548	1,233			24,133		21,202		1,125	-	5	2,326	1,023	3,423	396	462	245,101	7,866	-	3.4	548	4,280	7.8	0.6	2.7	2,116
2010																														
COMMERCIAL:																														
New Construction																														
EE Building Design (30% Large)	1	115	18	133	130	263	51%	49%	1,320	95%	1,254	25	542	-	17	149	856	199	23.8	387	15,466	6,582	-	1.1	130	610	4.7	0.4	3.8	742
EE Building Design (30% Small)	1	42	16	58	48	105	55%	45%	486	95%	462	25	189	-	18	55	299	73	8.8	135	5,695	2,299	-	1.0	48	217	4.6	0.4	3.4	249
EE Building Design (60%)	1	442	23	465	500	965	48%	52%	2,657	95%	2,524	25	2,169	-	31	301	3,424	401	48.0	1,547	31,136	26,335	-	0.6	500	1,996	4.0	0.3	3.9	2,759
High Performance Glazing HIT	1	71	-	71	80	151	47%	53%	566	95%	537	25	144	-	23	64	228	85	10.2	103	6,627	1,751	-	0.9	80	198	2.5	0.4	1.9	141
Near Condensing Boiler	1	18	7	26	18	44	58%	42%	640	82%	525	25	-	-	7	62	N/A	97	11.6	N/A	6,473	-	-	2.4	18	108	5.9	0.5	1.4	19
Condensing Boiler	2	69	3	72	69	142	51%	49%	2,228	82%	1,827	25	-	-	6	218	N/A	336	40.3	N/A	22,535	-	-	3.0	69	376	5.4	0.5	1.5	76
Instantaneous DHW Heater	4	4	3.5	8	4	12	65%	35%	293	85%	249	15	-	-	5	22	N/A	34	4.1	N/A	2,358	-	-	2.8	4	38	9.0	0.5	1.8	10
Condensing DHW Boiler	2	17	2.0	19	17	36	53%	47%	2,476	100%	2,476	25	-	-	1	295	N/A	373	44.7	N/A	30,540	-	-	15.5	17	418	24.6	0.8	8.2	259
Condensing DHW Heater	2	2	2.0	4	2	6	67%	33%	216	100%	216	10	-	-	4	14	N/A	19	2.3	N/A	1,559	-	-	3.4	2	21	10.5	0.6	2.3	8
Drainwater Heat Recovery	2	18	3	20	18	38	53%	47%	886	98%	868	20	-	-	4	91	N/A	120	14.5	N/A	9,661	-	-	4.5	18	134	7.7	0.6	2.4	53
Retrofit																														
Near Condensing Boiler	10	225	31	255	225	480	53%	47%	9,750	80%	7,800	25	-	-	5	929	N/A	1,471	176.2	N/A	96,209	-	-	3.6	225	1,647	7.3	0.5	1.9	449
Condensing Boiler	4	173	16	189	173	362	52%	48%	6,132	90%	5,519	25	-	-	5	657	N/A	925	110.8	N/A	68,072	-	-	3.5	173	1,036	6.0	0.6	1.8	295
Building Recommissioning	4	128	46	174	128	302	58%	42%	3,900	95%	3,705	10	1,800	-	11	236	1,636	339	42.5	739	26,785	12,586	-	1.4	128	1,120	8.8	0.5	6.2	1,569
Next Generation Building Automation System	1	40	7	47	40	87	54%	46%	487	95%	463	10	225	-	26	29	205	42	5.3	92	3,345	1,573	-	0.6	40	140	3.5	0.3	2.7	147
High Efficiency Roof Top Unit	1	5	3	8	5	12	63%	37%	122	100%	122	20	-	-	9	13	N/A	16	2.0	N/A	1,355	-	-	1.7	5	18	4.1	0.5	1.1	1
Instantaneous DHW Heaters	6	6	34	41	6	47	87%	13%	439	90%	395	15	-	-	12	34	N/A	50	6.2	N/A	3,746	-	-	0.8	6	57	9.0	0.4	0.7	(13)
Condensing DHW Boiler	5	43	15	58	43	100	58%	43%	6,190	95%	5,881	25	-	-	1	700	N/A	934	111.8	N/A	72,533	-	-	12.2	43	1,046	24.6	0.7	7.0	600
Condensing DHW Heater	6	6	18	24	6	30	80%	20%	647	95%	614	10	-	-	7	39	N/A	56	7.0	N/A	4,442	-	-	1.6	6	63	10.5	0.5	1.3	9
2010																														
Total Commercial	54	1,422	249	1,671	1,511	3,182			39,434		35,436		5,069	-	8	3,907	6,646	5,570	670	3,003	408,535	51,125	-	2.3	1,511	9,243	6.1	0.5	3.3	7,372

		SHEET LABELS
	Residential	
New Construction		
	EE Building Design (30% Large)	**EnerEffBldg Large**
	EE Building Design (30% Small)	**EnerEffBldg Small**
	EE Building Design (60%)	**EEBldg 60%**
	High Performance Glazing HIT	**HP Glazing Unit**
	Near Condensing Boiler	**NearCond Boilers**
	Condensing Boiler	**Cond Boilers**
	Instantaneous DHW Heater	**Inst DHW Heaters**
	Condensing DHW Boiler	**Cond DHW Boilers**
	Condensing DHW Heater	**Cond DHW Heaters**
	Drainwater Heat Recovery	**Drainwater Heat Rec**
Retrofit		
	Near Condensing Boiler	**Retrofit NearCondBoilers**
	Condensing Boiler	**Retrofit CondBoilers**
	Building Recommissioning	**Retrofit Bldg Re-Comm**
	Next Generation Building Automation System	**Retrofit NextGenBAS**
	High Efficiency Roof Top Unit	**Retrofit HE Roof Top**
	Instantaneous DHW Heaters	**Retrofit Inst DHW Heaters**
	Condensing DHW Boiler	**Retrofit Cond DHW Boilers**
	Condensing DHW Heater	**Retrofit Cond DHW Heaters**

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for EE Building Design (30% Large)

PER MEASURE

Total Cost	$ 260,000		
Incentive	**$ 130,000**	$114,874	Present Value accounts for any implementation lag
Participant	**$ 130,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	**2**	Years		
Energy Savings per installation	**1504.0**	GJ	1,320	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**5%**	95%		Net-to-Gross
Alternate Energy Impact	**2030.0**	GJ	541,992	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1	1	**0**	**0**	**1**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,096	1,320	-	-	1,320	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	1,042	1,254	-	-	1,254	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	450,208	541,992	-	-	541,992	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 149,303	$ 149,303	$ -	$ -	$ 149,303	
Utility Program Costs						
DSM Incentives		$ 114,874	$ -	$ -	$ 114,874	Including Implementation Lag
Administration		$ 18,333	**$ -**	**$ -**	**$ 18,333**	
Subtotal	$ 110,649	$ 133,207	$ -	$ -	$ 133,207	
Participants' Net Costs						
Incremental Cost		$ 130,000	$ -	$ -	$ 130,000	
Subtotal	$ 107,985	$ 130,000	$ -	$ -	$ 130,000	
Alternate Savings - Net						
Energy (Purchases)		$ 855,668	$ -	$ -	$ 855,668	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 855,668	$ 855,668	$ -	$ -	$ 855,668	
Net Present Benefit (Cost)	$ 786,337	$ 741,763	$ -	$ -	$ 741,763	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.6**		-	-	**3.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 17.02**		**$ -**	**$ -**	**$ 17.02**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for EE Building Design (30% Small)

PER MEASURE

Total Cost	$ 95,000		
Incentive	$ 47,500	$41,973	Present Value accounts for any implementation lag
Participant	$ 47,500		

Annual Impact Per Measure				Average Annnual Energy Savings per Measure
Time to impementation	2	Years		
Energy Savings per installation	550.0	GJ	486	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	5%	95%		Net-to-Gross
Alternate Energy Impact	709.0	GJ	189,297	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1	1	0	0	1	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	404	486	-	-	486	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	384	462	-	-	462	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	157,240	189,297	-	-	189,297	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 54,977	$ 54,977	$ -	$ -	$ 54,977	
Utility Program Costs						
DSM Incentives		$ 41,973	$ -	$ -	$ 41,973	Including Implementation Lag
Administration		$ 15,833	$ -	$ -	$ 15,833	
Subtotal	$ 48,017	$ 57,806	$ -	$ -	$ 57,806	
Participants' Net Costs						
Incremental Cost		$ 47,500	$ -	$ -	$ 47,500	
Subtotal	$ 39,456	$ 47,500	$ -	$ -	$ 47,500	
Alternate Savings - Net						
Energy (Purchases)		$ 298,851	$ -	$ -	$ 298,851	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 298,851	$ 298,851	$ -	$ -	$ 298,851	
Net Present Benefit (Cost)	$ 266,356	$ 248,522	$ -	$ -	$ 248,522	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.0**		-	-	**3.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 18.49**		**$ -**	**$ -**	**$ 18.49**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for EE Building Design (60%)

PER MEASURE

Total Cost	$ 1,000,000		
Incentive	$ 500,000	$441,825	Present Value accounts for any implementation lag
Participant	$ 500,000		

Annual Impact Per Measure				Average Annnual Energy Savings per Measure
Time to impementation	2	Years		
Energy Savings per installation	3007.0	GJ	2,657	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	5%	95%		Net-to-Gross
Alternate Energy Impact	8122.0	GJ	2,168,504	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1	1	0	0	1	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	2,207	2,657	-	-	2,657	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	2,097	2,524	-	-	2,524	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	1,801,276	2,168,504	-	-	2,168,504	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 300,576	$ 300,576	$ -	$ -	$ 300,576	
Utility Program Costs						
DSM Incentives		$ 441,825	$ -	$ -	$ 441,825	Including Implementation Lag
Administration		$ 23,333	$ -	$ -	$ 23,333	
Subtotal	$ 386,385	$ 465,158	$ -	$ -	$ 465,158	
Participants' Net Costs						
Incremental Cost		$ 500,000	$ -	$ -	$ 500,000	
Subtotal	$ 415,327	$ 500,000	$ -	$ -	$ 500,000	
Alternate Savings - Net						
Energy (Purchases)		$ 3,423,513	$ -	$ -	$ 3,423,513	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 3,423,513	$ 3,423,513	$ -	$ -	$ 3,423,513	
Net Present Benefit (Cost)	$ 2,922,377	$ 2,758,932	$ -	$ -	$ 2,758,932	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.6**		-	-	**3.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 31.00**		**$ -**	**$ -**	**$ 31.00**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for High Performance Glazing HIT

PER MEASURE

Total Cost	$ 160,000		
Incentive	**$ 80,000**	$70,692	Present Value accounts for any implementation lag
Participant	**$ 80,000**		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	**2**	Years		
Energy Savings per installation	**640.0**	GJ	566	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**5%**	95%		Net-to-Gross
Alternate Energy Impact	**540.0**	GJ	144,175	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1	1	**0**	**0**	**1**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	470	566	-	-	566	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	446	537	-	-	537	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	119,760	144,175	-	-	144,175	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 63,974	$ 63,974	$ -	$ -	$ 63,974	
Utility Program Costs						
DSM Incentives		$ 70,692	$ -	$ -	$ 70,692	Including Implementation Lag
Administration		$ -	$ -	$ -	$ -	
Subtotal	$ 58,721	$ 70,692	$ -	$ -	$ 70,692	
Participants' Net Costs						
Incremental Cost		$ 80,000	$ -	$ -	$ 80,000	
Subtotal	$ 66,452	$ 80,000	$ -	$ -	$ 80,000	
Alternate Savings - Net						
Energy (Purchases)		$ 227,616	$ -	$ -	$ 227,616	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 227,616	$ 227,616	$ -	$ -	$ 227,616	
Net Present Benefit (Cost)	$ 166,417	$ 140,898	$ -	$ -	$ 140,898	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.3**		-	-	**1.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 22.74**		**$ -**	**$ -**	**$ 22.74**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Near Condensing Boiler

PER MEASURE

Total Cost	$ 36,600		
Incentive	**$ 18,300**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 18,300**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	**-**	Years	
Energy Savings per installation	**640.0**	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**18%**	82%	Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	3	**1**	**1**	**1**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,699	1,920	640	640	640	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	1,393	1,574	525	525	525	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 186,558	$ 186,558	$ 62,124	$ 61,944	$ 62,490	
Utility Program Costs						
DSM Incentives		$ 54,900	$ 18,300	$ 18,300	$ 18,300	Including Implementation Lag
Administration		$ 23,649	**$ 9,083**	**$ 7,283**	**$ 7,283**	
Subtotal	$ 69,598	$ 78,549	$ 27,383	$ 25,583	$ 25,583	
Participants' Net Costs						
Incremental Cost		$ 54,900	$ 18,300	$ 18,300	$ 18,300	
Subtotal	$ 48,574	$ 54,900	$ 18,300	$ 18,300	$ 18,300	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 68,386	$ 53,109	$ 16,441	$ 18,061	$ 18,607	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.6**		**1.4**	**1.4**	**1.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 6.88**		**$ 7.06**	**$ 6.78**	**$ 6.78**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Condensing Boiler

PER MEASURE

Total Cost	$ 69,200		
Incentive	$ 34,600	No Lag	Present Value accounts for any implementation lag
Participant	$ 34,600		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	1114.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	18%	82%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	4	1	1	2	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	3,882	4,456	1,114	1,114	2,228	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	3,183	3,654	913	913	1,827	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 433,499	$ 433,499	$ 108,134	$ 107,822	$ 217,544	
Utility Program Costs						
DSM Incentives		$ 138,400	$ 34,600	$ 34,600	$ 69,200	Including Implementation Lag
Administration		$ 7,291	$ 2,083	$ 2,083	$ 3,125	
Subtotal	$ 126,975	$ 145,691	$ 36,683	$ 36,683	$ 72,325	
Participants' Net Costs						
Incremental Cost		$ 138,400	$ 34,600	$ 34,600	$ 69,200	
Subtotal	$ 120,580	$ 138,400	$ 34,600	$ 34,600	$ 69,200	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 185,944	$ 149,408	$ 36,851	$ 36,539	$ 76,019	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.8**		**1.5**	**1.5**	**1.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 6.30**		**$ 6.33**	**$ 6.33**	**$ 6.28**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Instantaneous DHW Heater

PER MEASURE

Total Cost	$ 2,100		
Incentive	**$ 1,050**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 1,050**		

Annual Impact Per Measure

			Average Annnual Energy Savings per Measure	
Time to impementation	**-**	Years		
Energy Savings per installation	**73.2**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**15%**	85%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**15**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	8	9	**2**	**3**	**4**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	575	659	146	220	293	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	489	560	124	187	249	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ 48,361	$ 48,361	$ 10,795	$ 16,039	$ 21,527	
Utility Program Costs						
DSM Incentives		$ 9,450	$ 2,100	$ 3,150	$ 4,200	Including Implementation Lag
Administration		$ 7,500	**$ 1,500**	**$ 2,500**	**$ 3,500**	
Subtotal	$ 14,773	$ 16,950	$ 3,600	$ 5,650	$ 7,700	
Participants' Net Costs						
Incremental Cost		$ 9,450	$ 2,100	$ 3,150	$ 4,200	
Subtotal	$ 8,246	$ 9,450	$ 2,100	$ 3,150	$ 4,200	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 25,342	$ 21,961	$ 5,095	$ 7,239	$ 9,627	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.1**		**1.9**	**1.8**	**1.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.97**		**$ 4.83**	**$ 4.98**	**$ 5.05**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Condensing DHW Boiler

PER MEASURE

Total Cost	$ 17,000		
Incentive	**$ 8,500**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 8,500**		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	**-**	Years		
Energy Savings per installation	**1238.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	4	**1**	**1**	**2**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	4,314	4,952	1,238	1,238	2,476	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	4,314	4,952	1,238	1,238	2,476	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 587,503	$ 587,503	$ 146,550	$ 146,126	$ 294,827	
Utility Program Costs						
DSM Incentives		$ 34,000	$ 8,500	$ 8,500	$ 17,000	Including Implementation Lag
Administration		$ 4,000	**$ 1,000**	**$ 1,000**	**$ 2,000**	
Subtotal	$ 33,107	$ 38,000	$ 9,500	$ 9,500	$ 19,000	
Participants' Net Costs						
Incremental Cost		$ 34,000	$ 8,500	$ 8,500	$ 17,000	
Subtotal	$ 29,622	$ 34,000	$ 8,500	$ 8,500	$ 17,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 524,773	$ 515,503	$ 128,550	$ 128,126	$ 258,827	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**9.4**		**8.1**	**8.1**	**8.2**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 1.18**		**$ 1.18**	**$ 1.18**	**$ 1.18**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Condensing DHW Heater

PER MEASURE

Total Cost	$ 2,000			
Incentive	**$ 1,000**		No Lag	Present Value accounts for any implementation lag
Participant	**$ 1,000**			

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	**-**	Years		
Energy Savings per installation	**107.8**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**10**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	4	**1**	**1**	**2**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	376	431	108	108	216	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	376	431	108	108	216	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$64.83	$63.53	$63.61	
Energy Purchases	$ 27,551	$ 27,551	$ 6,988	$ 6,848	$ 13,714	
Utility Program Costs						
DSM Incentives		$ 4,000	$ 1,000	$ 1,000	$ 2,000	Including Implementation Lag
Administration		$ 4,000	**$ 1,000**	**$ 1,000**	**$ 2,000**	
Subtotal	$ 6,970	$ 8,000	$ 2,000	$ 2,000	$ 4,000	
Participants' Net Costs						
Incremental Cost		$ 4,000	$ 1,000	$ 1,000	$ 2,000	
Subtotal	$ 3,485	$ 4,000	$ 1,000	$ 1,000	$ 2,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 17,096	$ 15,551	$ 3,988	$ 3,848	$ 7,714	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.6**		**2.3**	**2.3**	**2.3**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.85**		**$ 3.85**	**$ 3.85**	**$ 3.85**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Drainwater Heat Recovery

PER MEASURE

Total Cost	$ 17,500		
Incentive	**$ 8,750**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 8,750**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	**-**	Years		
Energy Savings per installation	**443.1**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**2%**	98%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**20**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	4	**1**	**1**	**2**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,544	1,772	443	443	886	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	1,513	1,737	434	434	868	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$104.27	$103.83	$104.75	
Energy Purchases	$ 181,337	$ 181,337	$ 45,278	$ 45,087	$ 90,972	
Utility Program Costs						
DSM Incentives		$ 35,000	$ 8,750	$ 8,750	$ 17,500	Including Implementation Lag
Administration		$ 5,667	**$ 1,542**	**$ 1,542**	**$ 2,583**	
Subtotal	$ 35,451	$ 40,667	$ 10,292	$ 10,292	$ 20,083	
Participants' Net Costs						
Incremental Cost		$ 35,000	$ 8,750	$ 8,750	$ 17,500	
Subtotal	$ 30,494	$ 35,000	$ 8,750	$ 8,750	$ 17,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.491 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 115,392	$ 105,670	$ 26,236	$ 26,045	$ 53,389	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.7**		**2.4**	**2.4**	**2.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.92**		**$ 3.94**	**$ 3.94**	**$ 3.89**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Near Condensing Boiler

PER MEASURE

Total Cost	$ 44,900		
Incentive	**$ 22,450**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 22,450**		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	**-**	Years		
Energy Savings per installation	**975.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**20%**	80%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	24	27	**8**	**9**	**10**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	23,185	26,325	7,800	8,775	9,750	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	18,548	21,060	6,240	7,020	7,800	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 2,496,043	$ 2,496,043	$ 738,667	$ 828,598	$ 928,778	
Utility Program Costs						
DSM Incentives		$ 606,150	$ 179,600	$ 202,050	$ 224,500	Including Implementation Lag
Administration		$ 88,523	**$ 28,624**	**$ 28,908**	**$ 30,991**	
Subtotal	$ 612,047	$ 694,673	$ 208,224	$ 230,958	$ 255,491	
Participants' Net Costs						
Incremental Cost		$ 606,150	$ 179,600	$ 202,050	$ 224,500	
Subtotal	$ 533,852	$ 606,150	$ 179,600	$ 202,050	$ 224,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 1,350,144	$ 1,195,220	$ 350,843	$ 395,590	$ 448,787	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.2**		**1.9**	**1.9**	**1.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.01**		**$ 5.04**	**$ 5.00**	**$ 4.99**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Condensing Boiler

PER MEASURE

Total Cost	$ 86,500			
Incentive	**$ 43,250**		No Lag	Present Value accounts for any implementation lag
Participant	**$ 43,250**			

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**1533.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**10%**	90%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	7	8	**1**	**3**	**4**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	10,599	12,264	1,533	4,599	6,132	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	9,539	11,038	1,380	4,139	5,519	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 1,309,024	$ 1,309,024	$ 163,323	$ 488,554	$ 657,146	
Utility Program Costs						
DSM Incentives		$ 346,000	$ 43,250	$ 129,750	$ 173,000	Including Implementation Lag
Administration		$ 32,666	**$ 4,083**	**$ 12,250**	**$ 16,333**	
Subtotal	$ 327,243	$ 378,666	$ 47,333	$ 142,000	$ 189,333	
Participants' Net Costs						
Incremental Cost		$ 346,000	$ 43,250	$ 129,750	$ 173,000	
Subtotal	$ 299,013	$ 346,000	$ 43,250	$ 129,750	$ 173,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 682,768	$ 584,358	$ 72,740	$ 216,804	$ 294,813	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.1**		**1.8**	**1.8**	**1.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.32**		**$ 5.32**	**$ 5.32**	**$ 5.32**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Building Recommissioning

PER MEASURE

Total Cost	$ 64,000		
Incentive	**$ 32,000**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 32,000**		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	**975.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**5%**	95%		Net-to-Gross
Alternate Energy Impact	**1620.0**	GJ	450,000	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**10**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	7	8	**2**	**2**	**4**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	6,796	7,800	1,950	1,950	3,900	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	6,456	7,410	1,853	1,853	3,705	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	3,136,485	3,600,000	900,000	900,000	1,800,000	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$64.83	$63.53	$63.61	
Energy Purchases	$ 473,447	$ 473,447	$ 120,092	$ 117,688	$ 235,667	
Utility Program Costs						
DSM Incentives		$ 256,000	$ 64,000	$ 64,000	$ 128,000	Including Implementation Lag
Administration		$ 98,667	**$ 26,167**	**$ 26,167**	**$ 46,333**	
Subtotal	$ 309,246	$ 354,667	$ 90,167	$ 90,167	$ 174,333	
Participants' Net Costs						
Incremental Cost		$ 256,000	$ 64,000	$ 64,000	$ 128,000	
Subtotal	$ 223,039	$ 256,000	$ 64,000	$ 64,000	$ 128,000	
Alternate Savings - Net						
Energy (Purchases)		$ 3,272,295	$ 818,074	$ 818,074	$ 1,636,147	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 3,272,295	$ 3,272,295	$ 818,074	$ 818,074	$ 1,636,147	
Net Present Benefit (Cost)	$ 3,213,458	$ 3,135,075	$ 783,999	$ 781,595	$ 1,569,482	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**7.0**		**6.1**	**6.1**	**6.2**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 11.40**		**$ 11.51**	**$ 11.51**	**$ 11.29**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Next Generation Building Automation System

PER MEASURE

Total Cost	$ 80,000			
Incentive	$ 40,000		No Lag	Present Value accounts for any implementation lag
Participant	$ 40,000			

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	487.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	5%	95%		Net-to-Gross
Alternate Energy Impact	810.0	GJ	225,000	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	10	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	2	2	0	1	1	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	835	974	-	487	487	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	793	925	-	463	463	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	385,718	450,000	-	225,000	225,000	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$64.83	$63.53	$63.61	
Energy Purchases	$ 58,820	$ 58,820	$ -	$ 29,392	$ 29,428	
Utility Program Costs						
DSM Incentives		$ 80,000	$ -	$ 40,000	$ 40,000	Including Implementation Lag
Administration		$ 15,084	$ 1,000	$ 7,042	$ 7,042	
Subtotal	$ 81,584	$ 95,084	$ 1,000	$ 47,042	$ 47,042	
Participants' Net Costs						
Incremental Cost		$ 80,000	$ -	$ 40,000	$ 40,000	
Subtotal	$ 68,572	$ 80,000	$ -	$ 40,000	$ 40,000	
Alternate Savings - Net						
Energy (Purchases)		$ 409,037	$ -	$ 204,518	$ 204,518	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 409,037	$ 409,037	$ -	$ 204,518	$ 204,518	
Net Present Benefit (Cost)	$ 317,700	$ 292,773	$ (1,000)	$ 146,868	$ 146,905	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.1**		-	**2.7**	**2.7**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 26.19**		**$ -**	**$ 26.02**	**$ 26.02**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for High Efficiency Roof Top Unit

PER MEASURE

Total Cost	$ 9,000		
Incentive	$ 4,500	No Lag	Present Value accounts for any implementation lag
Participant	$ 4,500		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	121.8	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	20	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	2	2	0	1	1	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	209	244	-	122	122	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	209	244	-	122	122	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$104.27	$103.83	$104.75	
Energy Purchases	$ 25,405	$ 25,405	$ -	$ 12,647	$ 12,758	
Utility Program Costs						
DSM Incentives		$ 9,000	$ -	$ 4,500	$ 4,500	Including Implementation Lag
Administration		$ 7,084	$ 1,000	$ 3,042	$ 3,042	
Subtotal	$ 13,869	$ 16,084	$ 1,000	$ 7,542	$ 7,542	
Participants' Net Costs						
Incremental Cost		$ 9,000	$ -	$ 4,500	$ 4,500	
Subtotal	$ 7,714	$ 9,000	$ -	$ 4,500	$ 4,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.491 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 3,821	$ 321	$ (1,000)	$ 605	$ 716	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.2**		**-**	**1.1**	**1.1**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 9.29**		**$ -**	**$ 8.89**	**$ 8.89**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Instantaneous DHW Heaters

PER MEASURE

Total Cost	$ 2,100		
Incentive	**$ 1,050**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 1,050**		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	**73.2**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**10%**	90%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**15**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	10	12	**2**	**4**	**6**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	761	878	146	293	439	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	685	791	132	264	395	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ 68,264	$ 68,264	$ 11,430	$ 22,644	$ 34,191	
Utility Program Costs						
DSM Incentives		$ 12,600	$ 2,100	$ 4,200	$ 6,300	Including Implementation Lag
Administration		$ 78,400	**$ 22,000**	**$ 22,200**	**$ 34,200**	
Subtotal	$ 79,624	$ 91,000	$ 24,100	$ 26,400	$ 40,500	
Participants' Net Costs						
Incremental Cost		$ 12,600	$ 2,100	$ 4,200	$ 6,300	
Subtotal	$ 10,919	$ 12,600	$ 2,100	$ 4,200	$ 6,300	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ (22,279)	$ (35,336)	$ (14,770)	$ (7,956)	$ (12,609)	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**0.8**		**0.4**	**0.7**	**0.7**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 13.95**		**$ 20.99**	**$ 12.25**	**$ 12.49**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Condensing DHW Boiler

PER MEASURE

Total Cost	$ 17,000		
Incentive	$ 8,500	No Lag	Present Value accounts for any implementation lag
Participant	$ 8,500		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	1238.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	5%	95%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	9	10	2	3	5	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	10,751	12,380	2,476	3,714	6,190	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	10,214	11,761	2,352	3,528	5,881	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 1,395,118	$ 1,395,118	$ 278,444	$ 416,459	$ 700,215	
Utility Program Costs						
DSM Incentives		$ 85,000	$ 17,000	$ 25,500	$ 42,500	Including Implementation Lag
Administration		$ 30,000	$ 6,000	$ 9,000	$ 15,000	
Subtotal	$ 99,869	$ 115,000	$ 23,000	$ 34,500	$ 57,500	
Participants' Net Costs						
Incremental Cost		$ 85,000	$ 17,000	$ 25,500	$ 42,500	
Subtotal	$ 73,816	$ 85,000	$ 17,000	$ 25,500	$ 42,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 1,221,433	$ 1,195,118	$ 238,444	$ 356,459	$ 600,215	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**8.0**		**7.0**	**6.9**	**7.0**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 1.38**		**$ 1.38**	**$ 1.38**	**$ 1.38**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Condensing DHW Heater

PER MEASURE

Total Cost	$ 2,000		
Incentive	$ 1,000	No Lag	Present Value accounts for any implementation lag
Participant	$ 1,000		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

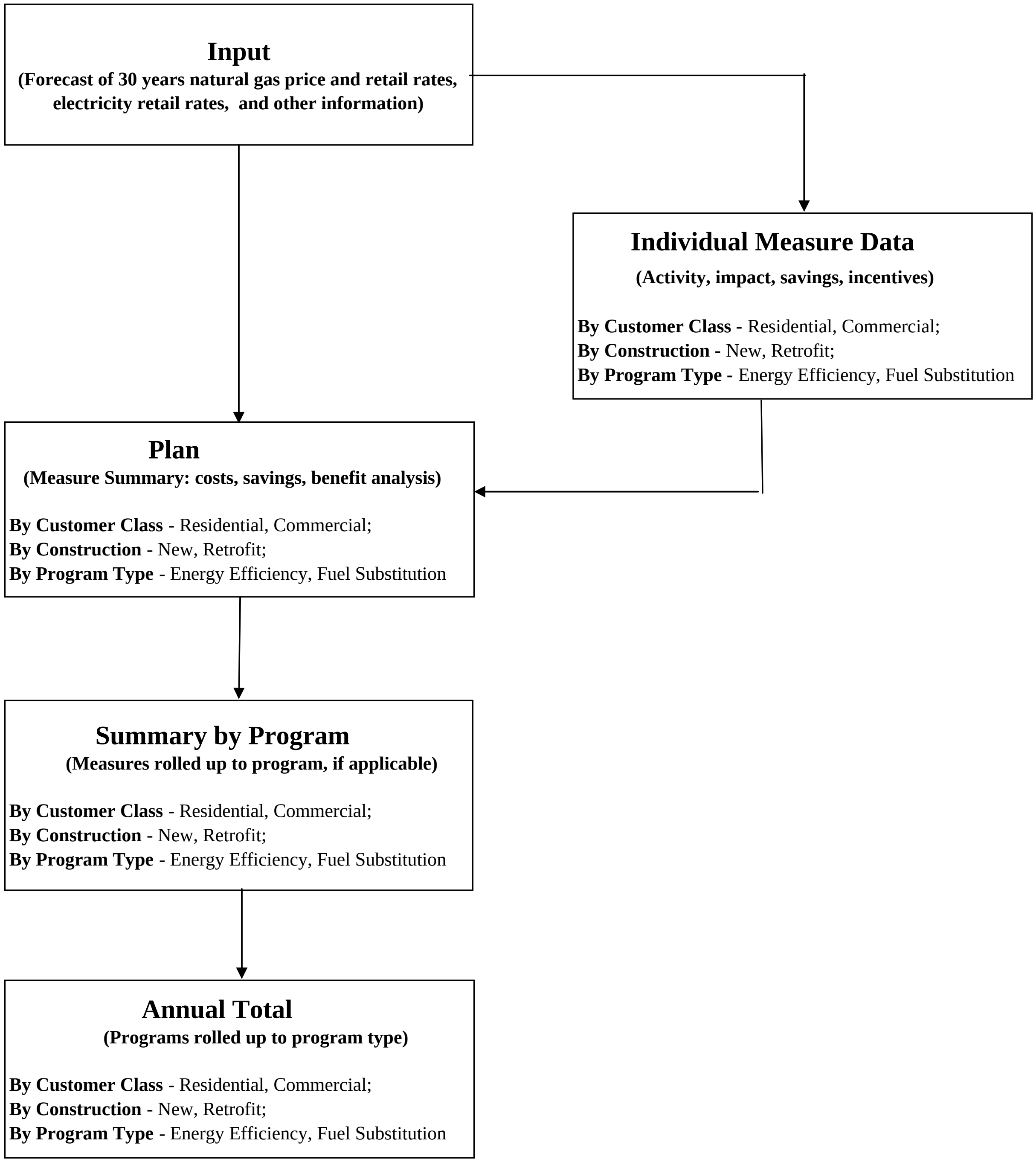
Time to impementation	-	Years		
Energy Savings per installation	107.8	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	5%	95%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	10	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	10	12	2	4	6	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,121	1,294	216	431	647	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	1,065	1,229	205	410	614	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$64.83	$63.53	$63.61	
Energy Purchases	$ 78,387	$ 78,387	$ 13,278	$ 26,024	$ 39,085	
Utility Program Costs						
DSM Incentives		$ 12,000	$ 2,000	$ 4,000	$ 6,000	Including Implementation Lag
Administration		$ 36,000	$ 6,000	$ 12,000	$ 18,000	
Subtotal	$ 41,594	$ 48,000	$ 8,000	$ 16,000	$ 24,000	
Participants' Net Costs						
Incremental Cost		$ 12,000	$ 2,000	$ 4,000	$ 6,000	
Subtotal	$ 10,399	$ 12,000	$ 2,000	$ 4,000	$ 6,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 26,394	$ 18,387	$ 3,278	$ 6,024	$ 9,085	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	1.5		1.3	1.3	1.3	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 6.75		$ 6.75	$ 6.75	$ 6.75	Informational (for comparison with supply options)

Table of Contents


Input
(Forecast of 30 years natural gas price and retail rates, electricity retail rates, and other information)
Individual Measure Data
(Activity, impact, savings, incentives)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Plan
(Measure Summary: costs, savings, benefit analysis)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Summary by Program
(Measures rolled up to program, if applicable)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Annual Total
(Programs rolled up to program type)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution

TERASEN GAS VANCOUVER ISLAND

		PROGRAM									ALTERNATE	
		COSTS ($000)							SAVINGS (GJ)		Impact	
		Utility									Energy	Capacity
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW
2008												
RESIDENTIAL:												
New Construction												
Energy Efficiency	522	63	67	130	7	137	95%	5%	2,859	2,429	26	-
Fuel Substitution	452	123	92	215	-6	210	103%	-3%	-6,903	-6,095	1,054	-
Retrofit												
Energy Efficiency	338	23	30	53	19	72	74%	26%	1,170	838	40	-
Fuel Substitution	1,200	278	183	461	180	641	72%	28%	-36,900	-35,918	9,785	-
Subtotals												
Residential Energy Efficiency	860	86	97	183	26	209	88%	12%	4,029	3,267	66	-
Residential Fuel Substitution	1,652	401	276	676	174	851	80%	20%	-43,803	-42,013	10,839	-
2008 Total Residential	**2,512**	**487**	**372**	**859**	**200**	**1,060**	**81%**	**19%**	**-39,774**	**-38,746**	**10,905**	**-**
2009												
RESIDENTIAL:												
New Construction												
Energy Efficiency	943	124	32	156	12	167	93%	7%	5,501	4,722	49	-
Fuel Substitution	731	187	36	223	-12	211	105%	-5%	-10,564	-9,274	1,615	-
Retrofit												
Energy Efficiency	625	45	22	66	37	103	64%	36%	2,233	1,603	78	-
Fuel Substitution	1,781	371	162	533	180	713	75%	25%	-41,580	-39,646	10,518	-
Subtotals												
Residential Energy Efficiency	1,568	168	54	222	48	270	82%	18%	7,734	6,325	127	-
Residential Fuel Substitution	2,512	558	198	756	168	924	82%	18%	-52,144	-48,921	12,133	-
2009 Total Residential	**4,080**	**726**	**252**	**978**	**217**	**1,195**	**82%**	**18%**	**-44,410**	**-42,596**	**12,260**	**-**
2010												
RESIDENTIAL:												
New Construction												
Energy Efficiency	1,507	189	43	232	21	253	92%	8%	8,479	7,231	88	-
Fuel Substitution	1,162	268	75	343	-23	320	107%	-7%	-15,488	-13,473	2,371	-
Retrofit												
Energy Efficiency	988	68	29	97	56	154	63%	37%	3,455	2,476	118	-
Fuel Substitution	2,350	463	128	591	180	771	77%	23%	-46,070	-43,204	11,217	-
Subtotals												
Residential Energy Efficiency	2,495	257	72	329	77	407	81%	19%	11,934	9,707	206	-
Residential Fuel Substitution	3,512	731	203	934	157	1,090	86%	14%	-61,558	-56,676	13,588	-
2010 Total Residential	**6,007**	**988**	**275**	**1,263**	**234**	**1,497**	**84%**	**16%**	**-49,624**	**-46,970**	**13,794**	**-**
2008 - 2010 (NPV 2007)												
RESIDENTIAL:												
New Construction												
Energy Efficiency	2,576	325	127	452	34	487	93%	7%	14,592	12,462	141	-
Fuel Substitution	2,036	504	181	684	-35	649	105%	-5%	-28,689	-25,115	4,386	-
Retrofit												
Energy Efficiency	1,691	118	71	189	97	287	66%	34%	5,943	4,261	205	-
Fuel Substitution	4,654	973	422	1,395	478	1,873	74%	26%	-109,697	-104,685	27,811	-
Subtotals												
Residential Energy Efficiency	**4,266**	**443**	**198**	**642**	**132**	**773**	**83%**	**17%**	**20,535**	**16,723**	**346**	**-**
Residential Fuel Substitution	**6,690**	**1,477**	**602**	**2,079**	**443**	**2,522**	**82%**	**18%**	**-138,387**	**-129,800**	**32,197**	**-**
2008 - 2010 Total Residential	**10,956**	**1,920**	**801**	**2,721**	**575**	**3,295**	**83%**	**17%**	**-117,852**	**-113,078**	**32,543**	**-**

	NET PRESENT VALUE									BENEFIT/COST						
	Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings				Participant					
	($/GJ)	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	Natural Gas Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2008																
RESIDENTIAL:																
New Construction																
Energy Efficiency	**5.7**	208	23	375	35	15	22,776	176	-	1.6	7	426	60.0	0.4	1.7	94
Fuel Substitution	**FS**	-409	923	-725	-67	512	(45,409)	7,097	-	FS	792	517	0.7	1.2	1.5	304
Retrofit																
Energy Efficiency	**6.7**	72	32	154	15	23	7,883	248	-	1.4	19	192	10.1	0.3	1.4	32
Fuel Substitution	**FS**	-3,469	13,497	-5,420	-511	6,662	(374,294)	103,821	-	FS	6,111	6,662	1.1	1.4	3.3	9,386
Subtotals																
Residential Energy Efficiency	**6.0**	280	55	530	50	39	30,659	424	-	**1.5**	**26**	**618**	**23.7**	**0.4**	**1.6**	**126**
Residential Fuel Substitution	**FS**	-3,878	14,419	-6,145	-578	7,174	(419,704)	110,918	-	**FS**	**6,897**	**7,174**	**1.0**	**1.3**	**3.0**	**9,691**
2008 Total Residential	**FS**	**-3,598**	**14,474**	**-5,615**	**-529**	**7,212**	**(389,045)**	**111,342**	**-**							
2009																
RESIDENTIAL:																
New Construction																
Energy Efficiency	**3.5**	402	43	724	73	29	44,364	334	-	2.6	12	826	70.6	0.5	2.7	278
Fuel Substitution	**FS**	-617	1,421	-1,122	-113	793	(69,732)	10,929	-	FS	1,235	805	0.7	1.3	1.7	593
Retrofit																
Energy Efficiency	**4.4**	137	63	296	30	46	15,139	485	-	2.1	37	371	10.1	0.4	1.9	97
Fuel Substitution	**FS**	-3,773	14,265	-6,060	-607	7,117	(410,062)	109,732	-	FS	6,847	7,117	1.0	1.4	3.2	9,779
Subtotals																
Residential Energy Efficiency	**3.7**	539	106	1,020	102	75	59,503	819	-	**2.4**	**48**	**1,197**	**24.7**	**0.4**	**2.4**	**375**
Residential Fuel Substitution	**FS**	-4,390	15,686	-7,182	-720	7,910	(479,794)	120,661	-	**FS**	**8,071**	**7,910**	**1.0**	**1.4**	**3.0**	**10,372**
2009 Total Residential	**FS**	**-3,851**	**15,792**	**-6,162**	**-618**	**7,985**	**(420,291)**	**121,479**	**-**							
2010																
RESIDENTIAL:																
New Construction																
Energy Efficiency	**3.4**	619	76	1,114	118	52	67,863	588	-	2.7	21	1,284	61.4	0.5	2.7	442
Fuel Substitution	**FS**	-913	2,102	-1,674	-179	1,186	(102,767)	16,172	-	FS	1,854	1,209	0.7	1.3	1.7	870
Retrofit																
Energy Efficiency	**4.2**	213	96	456	48	69	23,327	737	-	2.2	56	574	10.2	0.4	2.0	155
Fuel Substitution	**FS**	-4,116	14,996	-6,675	-699	7,551	(444,214)	115,352	-	FS	7,554	7,551	1.0	1.4	3.1	10,109
Subtotals																
Residential Energy Efficiency	**3.6**	832	172	1,571	166	121	91,190	1,325	-	**2.5**	**77**	**1,858**	**24.0**	**0.4**	**2.5**	**597**
Residential Fuel Substitution	**FS**	-5,029	17,098	-8,349	-878	8,738	(546,981)	131,524	-	**FS**	**9,385**	**8,738**	**0.9**	**1.4**	**2.8**	**10,979**
2010 Total Residential	**FS**	**-4,197**	**17,270**	**-6,779**	**-713**	**8,859**	**(455,791)**	**132,848**	**-**							
2008 - 2010 (NPV 2007)																
RESIDENTIAL:																
New Construction																
Energy Efficiency	**3.3**	1,229	143	2,214	226	96	135,002	1,097	-	2.7	34	2,536	73.8	0.5	2.8	885
Fuel Substitution	**FS**	-1,938	4,446	-3,521	-360	2,491	(217,908)	34,197	-	FS	3,881	2,526	0.7	1.3	1.7	1,859
Retrofit																
Energy Efficiency	**4.1**	423	191	907	92	138	46,350	1,469	-	2.2	97	1,137	11.7	0.4	2.1	327
Fuel Substitution	**FS**	-11,359	42,758	-18,156	-1,817	21,330	(1,228,570)	328,905	-	FS	20,451	21,330	1.0	1.4	3.2	29,526
Subtotals																
Residential Energy Efficiency	**3.5**	**1,651**	**334**	**3,120**	**318**	**235**	**181,352**	**2,567**	**-**	**2.6**	**132**	**3,673**	**27.9**	**0.4**	**2.6**	**1,212**
Residential Fuel Substitution	**FS**	**-13,296**	**47,203**	**-21,677**	**-2,177**	**23,821**	**(1,446,479)**	**363,103**	**-**	**FS**	**24,297**	**23,821**	**1.0**	**1.4**	**3.0**	**31,385**
2008 - 2010 Total Residential	**FS**	**-11,645**	**47,537**	**-18,556**	**-1,859**	**24,056**	**(1,265,127)**	**365,669**	**-**							

TERASEN GAS VANCOUVER ISLAND

		PROGRAM									ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings			Natural Gas	Participant			Natural Gas		TRC Net Benefits
		Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity							
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Rate Impact	Total Resource	($'000s)
2008																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	280	56	28	84	-	84	100%	0%	2,324	2,092	7	-	4	181	8	310	29	4	19,819	61	-	2.2	-	343	N/A	0.5	2.3	106
EE E* Hot Water Saving Appliances	242	7	39	46	7	53	87%	13%	535	338	19	-	16	27	15	66	6	11	2,957	115	-	0.6	7	83	11.7	0.2	0.8	(12)
Subtotal New Constuction Energy Efficiency	**522**	**63**	**67**	**130**	**7**	**137**	**95%**	**5%**	**2,859**	**2,429**	**26**	-	**6**	**208**	**23**	**375**	**35**	**15**	**22,776**	**176**	-	**1.6**	**7**	**426**	**60.0**	**0.4**	**1.7**	**94**
FS Natural Gas DHW	336	118	73	191	-	191	100%	0%	-6,317	-5,685	961	-	FS	(369)	828	(638)	(59)	448	(41,100)	6,368	-	FS	697	448	0.6	1.1	1.5	268
FS Gas Cooking Range	39	2	17	19	(2)	17	111%	-11%	(296)	(178)	33	-	FS	(17)	28	(44)	(4)	23	(1,872)	214	-	FS	48	25	0.5	1.2	0.8	(7)
FS Gas Clothes Dryer	77	4	2	5	(4)	2	350%	-250%	(290)	(232)	59	-	FS	(23)	67	(43)	(4)	41	(2,438)	515	-	FS	47	45	0.9	1.5	2.8	43
Subtotal New Construction Fuel Substitution	**452**	**123**	**92**	**215**	**(6)**	**210**	**103%**	**-3%**	**-6,903**	**-6,095**	**1,054**	-	**FS**	**(409)**	**923**	**(725)**	**(67)**	**512**	**(45,409)**	**7,097**	-	**FS**	**792**	**517**	**0.7**	**1.2**	**1.5**	**304**
Retrofit																												
EE E* Furnace Upgrade	30	9	1	10	9	19	52%	48%	309	222	-	-	4	22	-	46	4	-	2,342	-	-	2.3	9	50	5.6	0.4	1.2	3
EE EnerChoice Fireplace	20	4	0	4	-	4	100%	0%	166	149	1	-	3	13	1	22	2	0	1,416	4	-	2.9	-	25	N/A	0.5	3.1	9
EE E* Hot Water Saving Appliances	288	10	29	39	10	49	80%	20%	695	466	39	-	9	37	32	86	8	23	4,126	243	-	1.0	10	118	11.7	0.3	1.4	20
Subtotal Retrofit Energy Efficiency	**338**	**23**	**30**	**53**	**19**	**72**	**74%**	**26%**	**1,170**	**838**	**40**	-	**7**	**72**	**32**	**154**	**15**	**23**	**7,883**	**248**	-	**1.4**	**19**	**192**	**10.1**	**0.3**	**1.4**	**32**
FS E* Furnace Upgrade	600	180	99	279	180	459	61%	39%	-31,920	-31,920	9,000	-	FS	(3,118)	12,668	(4,740)	(447)	6,174	(335,966)	97,448	-	FS	5,367	6,174	1.2	1.4	3.5	9,092
FS EnerChoice Fireplace	150	30	59	89	-	89	100%	0%	-2,370	-2,133	417	-	FS	(185)	473	(316)	(30)	256	(20,211)	3,642	-	FS	345	256	0.7	1.2	1.7	199
FS Gas Cooking Range	225	34	13	47	-	47	100%	0%	(1,755)	(1,053)	194	-	FS	(103)	164	(261)	(25)	133	(11,083)	1,259	-	FS	285	133	0.5	1.7	1.1	14
FS Gas Clothes Dryer	225	34	13	47	-	47	100%	0%	(855)	(812)	175	-	FS	(64)	191	(104)	(10)	98	(7,034)	1,472	-	FS	114	98	0.9	0.9	1.7	81
Subtotal Retrofit Fuel Substitution	**1,200**	**278**	**183**	**461**	**180**	**641**	**72%**	**28%**	**(36,900)**	**(35,918)**	**9,785**	-	**FS**	**(3,469)**	**13,497**	**(5,420)**	**(511)**	**6,662**	**(374,294)**	**103,821**	-	**FS**	**6,111**	**6,662**	**1.1**	**1.4**	**3.3**	**9,386**
2008 Subtotal Energy Efficiency	**860**	**86**	**97**	**183**	**26**	**209**	**88%**	**12%**	**4,029**	**3,267**	**66**	-	**6**	**280**	**55**	**530**	**50**	**39**	**30,659**	**424**	-	**1.5**	**26**	**618**	**23.7**	**0.4**	**1.6**	**126**
2008 Subtotal Fuel Substitution	**1,652**	**401**	**276**	**676**	**174**	**851**	**80%**	**20%**	**(43,803)**	**(42,013)**	**10,839**	-	**FS**	**(3,878)**	**14,419**	**(6,145)**	**(578)**	**7,174**	**(419,704)**	**110,918**	-	**FS**	**6,897**	**7,174**	**1.0**	**1.3**	**3.0**	**9,691**
2008 Total Residential	**2,512**	**487**	**372**	**859**	**200**	**1,060**	**81%**	**19%**	**(39,774)**	**(38,746)**	**10,905**	-	**-**	**(3,598)**	**14,474**	**(5,615)**	**(529)**	**7,212**	**(389,045)**	**111,342**	-	**(4.2)**	**200**	**1,068**	**5.3**	**0.8**	**10.3**	**9,817**
2009																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	559	112	14	125	-	125	100%	0%	4,640	4,176	14	-	3	359	16	618	62	9	39,567	122	-	2.9	-	689	N/A	0.5	3.0	249
EE E* Hot Water Saving Appliances	384	12	18	30	12	42	72%	28%	862	546	35	-	6	43	27	106	11	20	4,796	211	-	1.4	12	137	11.7	0.3	1.7	29
Subtotal New Constuction Energy Efficiency	**943**	**124**	**32**	**156**	**12**	**167**	**93%**	**7%**	**5,501**	**4,722**	**49**	-	**4**	**402**	**43**	**724**	**73**	**29**	**44,364**	**334**	-	**2.6**	**12**	**826**	**70.6**	**0.5**	**2.7**	**278**
FS Natural Gas DHW	500	175	24	199	-	199	100%	0%	-9,400	-8,460	1,431	-	FS	(537)	1,232	(949)	(96)	667	(61,161)	9,476	-	FS	1,045	667	0.6	1.3	1.7	496
FS Gas Cooking Range	77	4	9	13	(4)	9	142%	-42%	(585)	(351)	65	-	FS	(34)	55	(87)	(9)	45	(3,696)	422	-	FS	96	48	0.5	1.8	1.3	12
FS Gas Clothes Dryer	154	8	3	11	(8)	3	350%	-250%	(579)	(463)	119	-	FS	(45)	134	(86)	(9)	82	(4,876)	1,030	-	FS	95	89	0.9	1.5	2.8	86
Subtotal New Construction Fuel Substitution	**731**	**187**	**36**	**223**	**(12)**	**211**	**105%**	**-5%**	**-10,564**	**-9,274**	**1,615**	-	**FS**	**(617)**	**1,421**	**(1,122)**	**(113)**	**793**	**(69,732)**	**10,929**	-	**FS**	**1,235**	**805**	**0.7**	**1.3**	**1.7**	**593**
Retrofit																												
EE E* Furnace Upgrade	60	18	1	19	18	37	52%	48%	618	445	-	-	4	43	-	92	9	-	4,683	-	-	2.3	18	101	5.6	0.4	1.2	6
EE EnerChoice Fireplace	40	8	1	9	-	9	100%	0%	332	299	1	-	3	26	1	44	4	1	2,831	9	-	2.9	-	49	N/A	0.5	3.0	18
EE E* Hot Water Saving Appliances	525	19	20	38	19	57	67%	33%	1,283	859	77	-	5	68	62	160	16	45	7,625	476	-	1.8	19	221	11.8	0.3	2.3	73
Subtotal Retrofit Energy Efficiency	**625**	**45**	**22**	**66**	**37**	**103**	**64%**	**36%**	**2,233**	**1,603**	**78**	-	**4**	**137**	**63**	**296**	**30**	**46**	**15,139**	**485**	-	**2.1**	**37**	**371**	**10.1**	**0.4**	**1.9**	**97**
FS E* Furnace Upgrade	600	180	86	266	180	446			-31,920	-31,920	9,000	-	FS	(3,100)	12,668	(4,740)	(474)	6,174	(335,966)	97,448	-	FS	5,394	6,174	1.1	1.4	3.6	9,122
FS EnerChoice Fireplace	281	56	49	105	-	105			-4,440	-3,996	781	-	FS	(343)	887	(591)	(59)	480	(37,863)	6,823	-	FS	651	480	0.7	1.3	2.0	438
FS Gas Cooking Range	450	68	13	81	-	81	100%	0%	(3,510)	(2,106)	388	-	FS	(205)	327	(521)	(52)	266	(22,166)	2,517	-	FS	573	266	0.5	1.8	1.1	42
FS Gas Clothes Dryer	450	68	13	81	-	81	100%	0%	(1,710)	(1,625)	350	-	FS	(126)	383	(208)	(21)	196	(14,067)	2,944	-	FS	229	196	0.9	1.0	1.9	176
Subtotal Retrofit Fuel Substitution	**1,781**	**371**	**162**	**533**	**180**	**713**	**75%**	**25%**	**(41,580)**	**(39,646)**	**10,518**	-	**FS**	**(3,773)**	**14,265**	**(6,060)**	**(607)**	**7,117**	**(410,062)**	**109,732**	-	**FS**	**6,847**	**7,117**	**1.0**	**1.4**	**3.2**	**9,779**
2009 Subtotal Energy Efficiency	**1,568**	**168**	**54**	**222**	**48**	**270**	**82%**	**18%**	**7,734**	**6,325**	**127**	-	**4**	**539**	**106**	**1,020**	**102**	**75**	**59,503**	**819**	-	**2.4**	**48**	**1,197**	**24.7**	**0.4**	**2.4**	**375**
2009 Subtotal Fuel Substitution	**2,512**	**558**	**198**	**756**	**168**	**924**	**82%**	**18%**	**(52,144)**	**(48,921)**	**12,133**	-	**FS**	**(4,390)**	**15,686**	**(7,182)**	**(720)**	**7,910**	**(479,794)**	**120,661**	-	**FS**	**8,071**	**7,910**	**1.0**	**1.4**	**3.0**	**10,372**
2009 Total Residential	**4,080**	**726**	**252**	**978**	**217**	**1,195**	**82%**	**18%**	**(44,410)**	**(42,596)**	**12,260**	-	**-**	**(3,851)**	**15,792**	**(6,162)**	**(618)**	**7,985**	**(420,291)**	**121,479**	-	**(3.9)**	**217**	**1,205**	**5.6**	**0.7**	**10.0**	**10,747**
2010																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	839	168	19	187	-	187	100%	0%	6,964	6,267	21	-	3	542	24	928	98	13	59,387	183	-	2.9	-	1,038	N/A	0.5	3.0	379
EE E* Hot Water Saving Appliances	668	21	24	45	21	66	68%	32%	1,515	963	67	-	5	77	53	187	20	39	8,476	404	-	1.7	21	246	11.8	0.3	2.0	63
Subtotal New Constuction Energy Efficiency	**1,507**	**189**	**43**	**232**	**21**	**253**	**92%**	**8%**	**8,479**	**7,231**	**88**	-	**3**	**619**	**76**	**1,114**	**118**	**52**	**67,863**	**588**	-	**2.7**	**21**	**1,284**	**61.4**	**0.5**	**2.7**	**442**
FS Natural Gas DHW	700	245	58	303	-	303	100%	0%	-13,160	-11,844	2,003	-	FS	(753)	1,725	(1,328)	(143)	934	(85,625)	13,267	-	FS	1,472	934	0.6	1.3	1.6	668
FS Gas Cooking Range	154	8	11	18	(8)	11	172%	-72%	(1,170)	(702)	130	-	FS	(69)	110	(174)	(18)	89	(7,391)	845	-	FS	192	97	0.5	2.0	1.4	30
FS Gas Clothes Dryer	308	15	6	22	(15)	6	350%	-250%	(1,158)	(926)	238	-	FS	(91)	268	(172)	(18)	163	(9,751)	2,060	-	FS	190	179	0.9	1.5	2.8	171
Subtotal New Construction Fuel Substitution	**1,162**	**268**	**75**	**343**	**(23)**	**320**	**107%**	**-7%**	**-15,488**	**-13,473**	**2,371**	-	**FS**	**(913)**	**2,102**	**(1,674)**	**(179)**	**1,186**	**(102,767)**	**16,172**	-	**FS**	**1,854**	**1,209**	**0.7**	**1.3**	**1.7**	**870**
Retrofit																												
EE E* Furnace Upgrade	90	27	2	29	27	56	52%	48%	927	667	-	-	4	65	-	138	14	-	7,025	-	-	2.3	27	152	5.6	0.4	1.2	10
EE EnerChoice Fireplace	60	12	1	13	-	13	100%	0%	498	448	2	-	3	39	2	66	7	1	4,247	13	-	2.9	-	74	N/A	0.5	3.1	27
EE E* Hot Water Saving Appliances	838	29	26	55	29	85	65%	35%	2,030	1,360	117	-	5	109	94	252	27	68	12,055	724	-	2.0	29	348	11.8	0.4	2.4	118
Subtotal Retrofit Energy Efficiency	**988**	**68**	**29**	**97**	**56**	**154**	**63%**	**37%**	**3,455**	**2,476**	**118**	-	**4**	**213**	**96**	**456**	**48**	**69**	**23,327**	**737**	-	**2.2**	56	574	**10.2**	**0.4**	**2.0**	**155**
FS E* Furnace Upgrade	600	180	41	221	180	401	55%	45%	-31,920	-31,920	9,000	-	FS	(3,124)	12,668	(4,740)	(495)	6,174	(335,966)	97,448	-	FS	5,416	6,174	1.1	1.4	3.6	9,143
FS EnerChoice Fireplace	400	80	52	132	-	132	100%	0%	-6,320	-5,688	1,111	-	FS	(492)	1,263	(842)	(89)	684	(53,897)	9,712	-	FS	931	684	0.7	1.3	2.0	639
FS Gas Cooking Range	675	101	18	119	-	119	100%	0%	(5,265)	(3,159)	581	-	FS	(309)	491	(782)	(82)	399	(33,249)	3,776	-	FS	864	399	0.5	1.8	1.1	63
FS Gas Clothes Dryer	675	101	18	119	-	119	100%	0%	(2,565)	(2,437)	525	-	FS	(190)	574	(311)	(33)	294	(21,101)	4,415	-	FS	345	294	0.9	1.0	1.9	265
Subtotal Retrofit Fuel Substitution	**2,350**	**463**	**128**	**591**	**180**	**771**	**77%**	**23%**	**(46,070)**	**(43,204)**	**11,217**	-	**FS**	**(4,116)**	**14,996**	**(6,675)**	**(699)**	**7,551**	**(444,214)**	**115,352**	-	**FS**	**7,554**	**7,551**	**1.0**	**1.4**	**3.1**	**10,109**
2010 Subtotal Energy Efficiency	**2,495**	**257**	**72**	**329**	**77**	**407**	**81%**	**19%**	**11,934**	**9,707**	**206**	-	**4**	**832**	**172**	**1,571**	**166**	**121**	**91,190**	**1,325**	-	**2.5**	**77**	**1,858**	**24.0**	**0.4**	**2.5**	**597**
2010 Subtotal Fuel Substitution	**3,512**	**731**	**203**	**934**	**157**	**1,090**	**86%**	**14%**	**(61,558)**	**(56,676)**	**13,588**	-	**FS**	**(5,029)**	**17,098**	**(8,349)**	**(878)**	**8,738**	**(546,981)**	**131,524**	-	**FS**	**9,385**	**8,738**	**0.9**	**1.4**	**2.8**	**10,979**
2010 Total Residential	**6,007**	**988**	**275**	**1,263**	**234**	**1,497**	**84%**	**16%**	**(49,624)**	**(46,970)**	**13,794**	-	**-**	**(4,197)**	**17,270**	**(6,779)**	**(713)**	**8,859**	**(455,791)**	**132,848**	-	**(3.3)**	**234**	**1,368**	**5.8**	**0.8**	**8.7**	**11,576**
2008 - 2010 (NPV 2007)																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	1,454	291	54	345	-	345	100%	0%	12,069	10,862	36	-	3	1,082	48	1,855	189	26	118,773	367	-	3.1	-	2,070	N/A	0.5	3.3	785
EE E* Hot Water Saving Appliances	1,122	34	73	107	34	142	76%	24%	2,523	1,600	105	-	7	146	95	359	37	70	16,229	731	-	1.4	34	466	13.6	0.3	1.7	100
Subtotal New Constuction Energy Efficiency	**2,576**	**325**	**127**	**452**	**34**	**487**	**93%**	**7%**	**14,592**	**12,462**	**141**	-	**3**	**1,229**	**143**	**2,214**	**226**	**96**	**135,002**	**1,097**	-	**2.7**	**34**	**2,536**	**73.8**	**0.5**	**2.8**	**885**
FS Natural Gas DHW	1,339	469	138	607	-	607	100%	0%	(25,176)	(22,658)	3,831	-	FS	(1,659)	3,784	(2,915)	(299)	2,049	(187,885)	29,111	-	FS	3,213	2,049	0.6	1.3	1.7	1,518
FS Gas Cooking Range	233	12	33	45	(12)	33	135%	-35%	(1,768)	(1,061)	196	-	FS	(120)	193	(305)	(31)	156	(12,959)	1,481	-	FS	336	168	0.5	1.8	1.3	39
FS Gas Clothes Dryer	464	23	9	33	(23)	9	350%	-250%	(1,746)	(1,397)	359	-	FS	(158)	469	(301)	(31)	286	(17,065)	3,605	-	FS	332	309	0.9	1.6	2.8	301
Subtotal New Construction Fuel Substitution	**2,036**	**504**	**181**	**684**	**(35)**	**649**	**105%**	**-5%**	**-28,689**	**-25,115**	**4,386**	-	**FS**	**(1,938)**	**4,446**	**(3,521)**	**(360)**	**2,491**	**(217,908)**	**34,197**	-	**FS**	**3,881**	**2,526**	**0.7**	**1.3**	**1.7**	**1,859**
Retrofit																												
EE E* Furnace Upgrade	156	47	3	50	47	97	52%	48%	1,607	1,157	-	-	4	130	-	275	28	-	14,050	-	-	2.6	47	303	6.5	0.4	1.3	34
EE EnerChoice Fireplace	104	21	2	23	-	23	100%	0%	863	777	3	-	3	77	3	133	14	2	8,494	26	-	3.4	-	148	N/A	0.5	3.5	58
EE E* Hot Water Saving Appliances	1,431	50	66	117	50	167	70%	30%	3,473	2,327	202	-	5	215	188	499	51	136	23,806	1,443	-	1.8	50	686	13.6	0.3	2.4	235
Subtotal Retrofit Energy Efficiency	**1,691**	**118**	**71**	**189**	**97**	**287**	**66%**	**34%**	**5,943**	**4,261**	**205**	-	**4**	**423**	**191**	**907**	**92**	**138**	**46,350**	**1,469**	-	**2.2**	**97**	**1,137**	**11.7**	**0.4**	**2.1**	**327**
FS E* Furnace Upgrade	1,593	478	203	681	478	1,159	59%	41%	(84,726)	(84,726)	23,889	-	FS	(9,342)	38,005	(14,220)	(1,417)	18,523	(1,007,899)	292,345	-	FS	16,115	18,523	1.1	1.4	3.6	27,504
FS EnerChoice Fireplace	722	144	142	286	-	286	100%	0%	(11,401)	(10,261)	2,004	-	FS	(1,020)	2,623	(1,749)	(178)	1,420	(111,971)	20,177	-	FS	1,927	1,420	0.7	1.3	2.0	1,316
FS Gas Cooking Range	1,170	175	38	214	-	214	100%	0%	(4,445)	(4,223)	910	-	FS	(379)	1,148	(623)	(64)	589	(42,202)	8,831	-	FS	687	589	0.9	1.0	1.9	555
FS Gas Clothes Dryer	1,170	175	38	214	-	214	100%	0%	(9,125)	(5,475)	1,007	-	FS	(617)	982	(1,564)	(158)	798	(66,499)	7,552	-	FS	1,722	798	0.5	1.9	1.2	151
Subtotal Retrofit Fuel Substitution	**4,654**	**973**	**422**	**1,395**	**478**	**1,873**	**74%**	**26%**	**(109,697)**	**(104,685)**	**27,811**	-	**FS**	**(11,359)**	**42,758**	**(18,156)**	**(1,817)**	**21,330**	**(1,228,570)**	**328,905**	-	**FS**	**20,451**	**21,330**	**1.0**	**1.4**	**3.2**	**29,526**
2008-2010 Subtotal Energy Efficiency	**4,266**	**443**	**198**	**642**	**132**	**773**	**83%**	**17%**	**20,535**	**16,723**	**346**	-	**4**	**1,651**	**334**	**3,120**	**318**	**235**	**181,352**	**2,567**	-	**2.6**	**132**	**3,673**	**27.9**	**0.4**	**2.6**	**1,212**
2008-2010 Subtotal Fuel Substitution	**6,690**	**1,477**	**602**	**2,079**	**443**	**2,522**	**82%**	**18%**	**(138,387)**	**(129,800)**	**32,197**	-	**FS**	**(13,296)**	**47,203**	**(21,677)**	**(2,177)**	**23,821**	**(1,446,479)**	**363,103**	-	**FS**	**24,297**	**23,821**	**0.98**	**1.4**	**3.0**	**31,385**
2008-2010 Total Residential	**10,956**	**1,920**	**801**	**2,721**	**575**	**3,295**	**83%**	**17%**	**(117,852)**	**(113,078)**	**32,543**	-	**-**	**(11,645)**	**47,537**	**(18,556)**	**(1,859)**	**24,056**	**(1,265,127)**	**365,669**	-	**(4.3)**	**575**	**3,641**	**6.3**	**0.7**	**10.9**	**32,597**

TERASEN GAS VANCOUVER ISLAND

		PROGRAM											ALTERNATE	
		COSTS ($000)							SAVINGS (GJ)			LIFE	Impact	
		Utility										Years	Energy	Capacity
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net-to-Gross	Net		MWh	kW
Label		B	C	D	E	F	G	H	Input (program)	J	K	L	M	N
Source Sheet or Calculation		Program	Program	B+C	Program	D+E	D/F	E/F	Program	Program	IxJ	Program	Program	Program
2008														
RESIDENTIAL:														
New Construction														
EE EnerChoice Fireplace	280	56	28	84	-	84	100%	0%	2,324	90%	2,092	15	7	-
EE E* Clothes Washer	42	2	35	37	2	39	95%	5%	119	67%	80	14	13	-
EE E* Dishwasher	200	5	4	9	5	14	64%	36%	416	62%	258	13	7	-
FS Natural Gas DHW	336	118	73	191	-	191	100%	0%	-6,317	90%	-5,685	10	961	-
FS Gas Cooking Range	39	2	17	19	(2)	17	111%	-11%	-296	60%	-178	18	33	-
FS Gas Clothes Dryer	77	4	2	5	(4)	2	350%	-250%	-290	80%	-232	18	59	-
Retrofit														
EE E* Furnace Upgrade	30	9	1	10	9	19	52%	48%	309	72%	222	18	-	-
EE EnerChoice Fireplace	20	4	0	4	-	4	100%	0%	166	90%	149	15	1	-
EE E * Dishwasher	175	4	27	31	4	36	88%	12%	368	67%	246	13	5	-
EE E* Clothes Washer	113	6	2	8	6	14	58%	42%	328	67%	220	14	34	-
FS E* Furnace Upgrade	600	180	99	279	180	459	61%	39%	-31,920	100%	-31,920	18	9,000	-
FS EnerChoice Fireplace	150	30	59	89	-	89	100%	0%	-2,370	90%	-2,133	15	417	-
FS Gas Cooking Range	225	34	13	47	-	47	100%	0%	-1,755	60%	-1,053	18	194	-
FS Gas Clothes Dryer	225	34	13	47	-	47	100%	0%	-855	95%	-812	13	175	-
2008														
Total Residential	2,512	487	372	859	200	1,060	81%	19%	-39,774		-38,746		10,905	-
2009														
RESIDENTIAL:														
New Construction														
EE EnerChoice Fireplace	559	112	14	125	-	125	100%	0%	4,640	90%	4,176	15	14	-
FS Natural Gas DHW	500	175	24	199	-	199	100%	0%	-9,400	90%	-8,460	10	1,431	-
EE E* Clothes Washer	84	4	12	17	4	21	80%	20%	238	67%	159	14	25	-
EE E* Dishwasher	300	8	6	14	8	21	64%	36%	624	62%	387	13	10	-
FS Gas Cooking Range	77	4	9	13	(4)	9	142%	-42%	-585	60%	-351	18	65	-
FS Gas Clothes Dryer	154	8	3	11	(8)	3	350%	-250%	-579	80%	-463	18	119	-
Retrofit														
FS E* Furnace Upgrade	600	180	86	266	$ 180.00	446	60%	40%	-31,920	100%	-31,920	18	9,000	-
EE E* Furnace Upgrade	60	18	1	19	$ 18.00	37	52%	48%	618	72%	445	18	-	-
FS EnerChoice Fireplace	281	56	49	105	$ -	105	100%	0%	-4,440	90%	-3,996	15	781	-
EE EnerChoice Fireplace	40	8	1	9	$ -	9	100%	0%	332	90%	299	15	1	-
EE E * Dishwasher	300	8	15	23	$ 7.50	30	75%	25%	630	67%	422	13	8	-
EE E* Clothes Washer	225	11	5	16	$ 11.25	27	58%	42%	653	67%	437	14	69	-
FS Gas Cooking Range	450	68	13	81	$ -	81	100%	0%	-3,510	60%	-2,106	18	388	-
FS Gas Clothes Dryer	450	68	13	81	$ -	81	100%	0%	-1,710	95%	-1,625	13	350	-
2009														
Total Residential	4,080	726	252	978	217	1,195	82%	18%	-44,410		-42,596		12,260	-
2010														
RESIDENTIAL:														
New Construction														
EE EnerChoice Fireplace	839	168	19	187	-	187	100%	0%	6,964	90%	6,267	15	21	-
FS Natural Gas DHW	700	245	58	303	-	303	100%	0%	-13,160	90%	-11,844	10	2,003	-
EE E* Clothes Washer	168	8	14	22	8	31	73%	27%	475	67%	319	14	50	-
EE E* Dishwasher	500	13	10	23	13	35	64%	36%	1,040	62%	645	13	17	-
FS Gas Cooking Range	154	8	11	18	(8)	11	172%	-72%	-1,170	60%	-702	18	130	-
FS Gas Clothes Dryer	308	15	6	22	(15)	6	350%	-250%	-1,158	80%	-926	18	238	-
Retrofit														
FS E* Furnace Upgrade	600	180	41	221	180	401	55%	45%	-31,920	100%	-31,920	18	9,000	-
EE E* Furnace Upgrade	90	27	2	29	27	56	52%	48%	927	72%	667	18	-	-
FS EnerChoice Fireplace	400	80	52	132	-	132	100%	0%	-6,320	90%	-5,688	15	1,111	-
EE EnerChoice Fireplace	60	12	1	13	-	13	100%	0%	498	90%	448	15	2	-
EE E * Dishwasher	500	13	19	32	13	44	72%	28%	1,050	67%	704	13	14	-
EE E* Clothes Washer	338	17	7	24	17	41	58%	42%	980	67%	657	14	103	-
FS Gas Cooking Range	675	101	18	119	-	119	100%	0%	-5,265	60%	-3,159	18	581	-
FS Gas Clothes Dryer	675	101	18	119	-	119	100%	0%	-2,565	95%	-2,437	13	525	-
2010														
Total Residential	6,007	988	275	1,263	234	1,497	84%	16%	-49,624		-46,970		13,794	-

	NET PRESENT VALUE									BENEFIT/COST						
	Levelized Cost	Utility Benefits		Participant Benefits (Costs)			Program Net Savings				Participant					
	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
Source Sheet or Calculation	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2008																
RESIDENTIAL:																
New Construction																
EE EnerChoice Fireplace	4	181	8	310	29	4	19,819	61	-	2.2	-	343	N/A	0.5	2.3	106
EE E* Clothes Washer	52	7	10	15	1	7	723	78	-	0.2	2	24	11.4	0.1	0.4	(23)
EE E* Dishwasher	4	20	5	51	5	4	2,233	37	-	2.2	5	59	11.8	0.3	1.8	11
FS Natural Gas DHW	FS	(369)	828	(638)	(59)	448	(41,100)	6,368	-	FS	697	448	0.6	1.1	1.5	268
FS Gas Cooking Range	FS	(17)	28	(44)	(4)	23	(1,872)	214	-	FS	48	25	0.5	1.2	0.8	(7)
FS Gas Clothes Dryer	FS	(23)	67	(43)	(4)	41	(2,438)	515	-	FS	47	45	0.9	1.5	2.8	43
Retrofit																
EE E* Furnace Upgrade	4	22	N/A	46	4	N/A	2,342	-	-	2.3	9	50	5.6	0.4	1.2	3
EE EnerChoice Fireplace	3	13	1	22	2	0	1,416	4	-	2.9	-	25	N/A	0.5	3.1	9
EE E * Dishwasher	15	19	4	45	4	3	2,132	29	-	0.6	4	52	11.8	0.3	0.6	(13)
EE E* Clothes Washer	4	18	28	42	4	20	1,994	214	-	2.3	6	66	11.7	0.4	3.4	32
FS E* Furnace Upgrade	FS	(3,118)	12,668	(4,740)	(447)	6,174	(335,966)	97,448	-	FS	5,367	6,174	1.2	1.4	3.5	9,092
FS EnerChoice Fireplace	FS	(185)	473	(316)	(30)	256	(20,211)	3,642	-	FS	345	256	0.7	1.2	1.7	199
FS Gas Cooking Range	FS	(103)	164	(261)	(25)	133	(11,083)	1,259	-	FS	285	133	0.5	1.7	1.1	14
FS Gas Clothes Dryer	FS	(64)	191	(104)	(10)	98	(7,034)	1,472	-	FS	114	98	0.9	0.9	1.7	81
2008																
Total Residential	FS	-3,598	14,474	-5,615	-529	7,212	(389,045)	111,342	-	FS	6,344	7,212	1.1	1.3	3.1	9,817
2009																
RESIDENTIAL:																
New Construction																
EE EnerChoice Fireplace	3	359	16	618	62	9	39,567	122	-	2.9	-	689	N/A	0.5	3.0	249
FS Natural Gas DHW	FS	(537)	1,232	(949)	(96)	667	(61,161)	9,476	-	FS	1,045	667	0.6	1.3	1.7	496
EE E* Clothes Washer	11	13	20	30	3	15	1,446	156	-	0.8	4	48	11.5	0.3	1.6	13
EE E* Dishwasher	4	30	7	76	8	6	3,350	55	-	2.2	8	89	11.9	0.3	1.8	16
FS Gas Cooking Range	FS	(34)	55	(87)	(9)	45	(3,696)	422	-	FS	96	48	0.5	1.8	1.3	12
FS Gas Clothes Dryer	FS	(45)	134	(86)	(9)	82	(4,876)	1,030	-	FS	95	89	0.9	1.5	2.8	86
Retrofit																
FS E* Furnace Upgrade	FS	(3,100)	12,668	(4,740)	(474)	6,174	(335,966)	97,448	-	FS	5,394	6,174	1.1	1.4	3.6	9,122
EE E* Furnace Upgrade	4	43	N/A	92	9	N/A	4,683	-	-	2.3	18	101	5.6	0.4	1.2	6
FS EnerChoice Fireplace	FS	(343)	887	(591)	(59)	480	(37,863)	6,823	-	FS	651	480	0.7	1.3	2.0	438
EE EnerChoice Fireplace	3	26	1	44	4	1	2,831	9	-	2.9	-	49	N/A	0.5	3.0	18
EE E * Dishwasher	6	33	6	76	8	5	3,655	49	-	1.4	8	89	11.8	0.3	1.3	9
EE E* Clothes Washer	4	36	55	83	8	40	3,970	427	-	2.3	11	132	11.7	0.4	3.4	64
FS Gas Cooking Range	FS	(205)	327	(521)	(52)	266	(22,166)	2,517	-	FS	573	266	0.5	1.8	1.1	42
FS Gas Clothes Dryer	FS	(126)	383	(208)	(21)	196	(14,067)	2,944	-	FS	229	196	0.9	1.0	1.9	176
2009																
Total Residential	FS	-3,851	15,792	-6,162	-618	7,985	(420,291)	121,479	-	FS	6,997	7,985	1.1	1.3	3.1	10,747
2010																
RESIDENTIAL:																
New Construction																
EE EnerChoice Fireplace	3	542	24	928	98	13	59,387	183	-	2.9	-	1,038	N/A	0.5	3.0	379
FS Natural Gas DHW	FS	(753)	1,725	(1,328)	(143)	934	(85,625)	13,267	-	FS	1,472	934	0.6	1.3	1.6	668
EE E* Clothes Washer	8	26	41	61	6	30	2,892	313	-	1.2	8	97	11.5	0.3	2.2	36
EE E* Dishwasher	4	50	12	126	13	9	5,584	91	-	2.2	13	149	11.9	0.3	1.8	27
FS Gas Cooking Range	FS	(69)	110	(174)	(18)	89	(7,391)	845	-	FS	192	97	0.5	2.0	1.4	30
FS Gas Clothes Dryer	FS	(91)	268	(172)	(18)	163	(9,751)	2,060	-	FS	190	179	0.9	1.5	2.8	171
Retrofit																
FS E* Furnace Upgrade	FS	(3,124)	12,668	(4,740)	(495)	6,174	(335,966)	97,448	-	FS	5,416	6,174	1.1	1.4	3.6	9,143
EE E* Furnace Upgrade	4	65	N/A	138	14	N/A	7,025	-	-	2.3	27	152	5.6	0.4	1.2	10
FS EnerChoice Fireplace	FS	(492)	1,263	(842)	(89)	684	(53,897)	9,712	-	FS	931	684	0.7	1.3	2.0	639
EE EnerChoice Fireplace	3	39	2	66	7	1	4,247	13	-	2.9	-	74	N/A	0.5	3.1	27
EE E * Dishwasher	5	55	11	127	14	8	6,092	82	-	1.7	13	149	11.9	0.3	1.5	21
EE E* Clothes Washer	4	54	83	125	13	61	5,963	641	-	2.3	17	199	11.8	0.4	3.4	97
FS Gas Cooking Range	FS	(309)	491	(782)	(82)	399	(33,249)	3,776	-	FS	864	399	0.5	1.8	1.1	63
FS Gas Clothes Dryer	FS	(190)	574	(311)	(33)	294	(21,101)	4,415	-	FS	345	294	0.9	1.0	1.9	265
2010																
Total Residential	FS	(4,197)	17,270	(6,779)	-713	8,859	(455,791)	132,848	-	FS	7,725	8,859	1.1	1.2	3.0	11,576

SHEET LABELS

Residential

New Construction		
	EE EnerChoice Fireplace	**FP**
	FS Natural Gas DHW	**NG DHW**
	EE E* Clothes Washer	**E Clothes**
	EE E* Dishwasher	**E Dish**
	FS Gas Cooking Range	**LB Range**
	FS Gas Clothes Dryer	**LB Dryer**
Retrofit		
	FS E* Furnace Upgrade	**Retrofit Furnace**
	EE E* Furnace Upgrade	
	FS EnerChoice Fireplace	**Retrofit FP**
	EE EnerChoice Fireplace	
	EE E * Dishwasher	**Retrofit E Dish**
	EE E* Clothes Washer	**Retrofit E Clothes**
	FS Gas Clothes Dryer	
	FS Gas Cooking Range	

2008

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for EE EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	8.3	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	10%	90%		Net-to-Gross
Alternate Energy Impact	0.09	GJ	25	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	15	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			3000	3000	3000	Information Only
Participants	1,454	1,678	280	559	839	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	12,069	13,927	2,324	4,640	6,964	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	10,862	12,535	2,092	4,176	6,267	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	36,352	41,950	7,000	13,975	20,975	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ 1,082,357	$ 1,082,357	$ 181,438	$ 358,814	$ 542,106	
Utility Program Costs						
DSM Incentives		$ 335,600	$ 56,000	$ 111,800	$ 167,800	
Administration		$ 60,540	$ 27,590	$ 13,680	$ 19,270	
Subtotal	$ 344,848	$ 396,140	$ 83,590	$ 125,480	$ 187,070	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 47,669	$ 7,954	$ 15,880	$ 23,835	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 47,669	$ 47,669	$ 7,954	$ 15,880	$ 23,835	
Net Present Benefit (Cost)	$ 785,179	$ 733,886	$105,802	$249,214	$378,870	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.3**		**2.3**	**3.0**	**3.0**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.35**		**$ 4.22**	**$ 3.17**	**$ 3.15**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for EE E* Clothes Washer

PER MEASURE

Total Cost	$	100
Incentive	$	50
Participant	$	50

Annual Impact Per Measure

Energy Savings per installation	2.83	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	33%	67%			Net-to-Gross
Alternate Energy Impact	1.0768	GJ		299	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	14	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			800	800	800	Information Only
Participants	253	294	42	84	168	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	717	832	119	238	475	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	480	557	80	159	319	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	75,752	87,939	12,563	25,125	50,251	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$82.51	$81.85	$82.39	
Energy Purchases	$ 45,852	$ 45,852	$ 6,571	$ 13,037	$ 26,244	
Utility Program Costs						
DSM Incentives		$ 14,700	$ 2,100	$ 4,200	$ 8,400	
Administration		$ 61,547	$ 35,173	$ 12,347	$ 14,027	
Subtotal	$ 68,288	$ 76,247	$ 37,273	$ 16,547	$ 22,427	
Participants' Net Costs						
Incremental Cost		$ 14,700	$ 2,100	$ 4,200	$ 8,400	
Subtotal	$ 12,663	$ 14,700	$ 2,100	$ 4,200	$ 8,400	
Alternate Savings - Net						
Energy (Purchases)		$ 71,195	$ 10,171	$ 20,341	$ 40,683	$1.208 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 71,195	$ 71,195	$ 10,171	$ 20,341	$ 40,683	
Net Present Benefit (Cost)	$ 36,095	$ 26,099	($22,631)	$12,631	$36,100	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.4**		**0.4**	**1.6**	**2.2**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 18.57**		**$ 54.45**	**$ 14.35**	**$ 10.66**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for EE E* Dishwasher

PER MEASURE

Total Cost	$	50
Incentive	$	25
Participant	$	25

Annual Impact Per Measure

Energy Savings per installation	2.08	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	38%	62%		Net-to-Gross
Alternate Energy Impact	0.12	GJ	33	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	13	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			1500	1500	1500	Information Only
Participants	868	1,000	200	300	500	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,806	2,080	416	624	1,040	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	1,120	1,290	258	387	645	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	28,948	33,333	6,667	10,000	16,667	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$78.30	$77.35	$78.05	
Energy Purchases	$ 100,448	$ 100,448	$ 20,196	$ 29,924	$ 50,327	
Utility Program Costs						
DSM Incentives		$ 25,000	$ 5,000	$ 7,500	$ 12,500	
Administration		$ 20,000	$ 4,000	$ 6,000	$ 10,000	
Subtotal	$ 39,079	$ 45,000	$ 9,000	$ 13,500	$ 22,500	
Participants' Net Costs						
Incremental Cost		$ 25,000	$ 5,000	$ 7,500	$ 12,500	
Subtotal	$ 21,711	$ 25,000	$ 5,000	$ 7,500	$ 12,500	
Alternate Savings - Net						
Energy (Purchases)		$ 23,784	$ 4,757	$ 7,135	$ 11,892	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 23,784	$ 23,784	$ 4,757	$ 7,135	$ 11,892	
Net Present Benefit (Cost)	$ 63,442	$ 54,232	$10,953	$16,060	$27,219	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	2.0		1.8	1.8	1.8	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 6.27		$ 6.27	$ 6.27	$ 6.27	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for FS Natural Gas DHW

PER MEASURE

Total Cost	$ 350				
Incentive	**$ 350**				
Participant	**$ -**				

Annual Impact Per Measure

Energy Savings per installation	**-18.8**	GJ			Average Annnual Energy Savings per
Free Rider Rate / Net-to-Gross	**10%**	90%			Net-to-Gross
Alternate Energy Impact	**10.3**	GJ		2,861	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	**10**	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010
Market Size			**1700**	**1700**	**1700**
Participants	1,339	1,536	**336**	**500**	**700**
Impact					
Gross Energy Savings (GJ)	-25,176	-28,877	-6,317	-9,400	-13,160
Net Energy Savings (GJ)	-22,658	-25,989	-5,685	-8,460	-11,844
Alternate Energy Impact (Increase) (kWh)	3,831,404	4,394,667	961,333	1,430,556	2,002,778
:ernate Capacity Impact (Increase) (kW/a)	-	-			

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010
Avoided Revenue Requirements					
PV $ per GJ			$64.83	$63.53	$63.61
Energy Purchases	$ (1,659,379)	$ (1,659,379)	$ (368,549)	$ (537,457)	$ (753,373)
Utility Program Costs					
DSM Incentives		$ 537,600	$ 117,600	$ 175,000	$ 245,000
Administration		$ 155,052	**$ 73,386**	**$ 23,833**	**$ 57,833**
Subtotal	$ 606,780	$ 692,652	$ 190,986	$ 198,833	$ 302,833
Participants' Net Costs					
Incremental Cost		$ -	$ -	$ -	$ -
Subtotal	$ -	$ -	$ -	$ -	$ -
Alternate Savings - Net					
Energy (Purchases)		$ 3,784,380	$ 827,833	$ 1,231,895	$ 1,724,653
Capacity (Purchases)		$ -	$ -	$ -	$ -
Subtotal	$ 3,784,380	$ 3,784,380	$ 827,833	$ 1,231,895	$ 1,724,653
Net Present Benefit (Cost)	$ 1,518,222	$ 1,432,350	$268,299	$495,604	$668,447
Benefit/Cost Ratio	**3.5**		**2.4**	**3.5**	**3.2**
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**

r Measure

Explanatory Notes
Information Only
Estimated Participatation

Extension of Unit Savings x No. of Upgrades
Gross Energy Savings less Free Riders
Other Utility Billed energy impact
Other Utility Billed capacity impact

$0.957 PV $ per kWh
PV$ per kW/a

Avoided Revenue Requirement less Utility + Participant Costs
Less planning, evaluation, research
Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for FS Gas Cooking Range

PER MEASURE

Total Cost	$	-
Incentive	$	50
Participant	$	(50)

Annual Impact Per Measure

Energy Savings per installation	-7.6	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	40%	60%			Net-to-Gross
Alternate Energy Impact	3.04	GJ		844	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			200	200	200	Information Only
Participants	233	270	39	77	154	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-1,768	-2,052	-296	-585	-1,170	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-1,061	-1,231	-178	-351	-702	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	196,437	228,000	32,933	65,022	130,044	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ (120,207)	$ (120,207)	$ (17,371)	$ (34,098)	$ (68,738)	
Utility Program Costs						
DSM Incentives		$ 13,500	$ 1,950	$ 3,850	$ 7,700	
Administration		$ 37,057	$ 17,103	$ 9,207	$ 10,747	
Subtotal	$ 44,771	$ 50,557	$ 19,053	$ 13,057	$ 18,447	
Participants' Net Costs						
Incremental Cost		$ (13,500)	$ (1,950)	$ (3,850)	$ (7,700)	
Subtotal	$ (11,631)	$ (13,500)	$ (1,950)	$ (3,850)	$ (7,700)	
Alternate Savings - Net						
Energy (Purchases)		$ 192,558	$ 27,814	$ 54,915	$ 109,829	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 192,558	$ 192,558	$ 27,814	$ 54,915	$ 109,829	
Net Present Benefit (Cost)	$ 39,211	$ 35,294	($6,660)	$11,610	$30,345	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.2**		**0.6**	**2.3**	**3.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for FS Gas Clothes Dryer

PER MEASURE

Total Cost	$	-
Incentive	$	50
Participant	$	(50)

Annual Impact Per Measure

Energy Savings per installation	-3.76	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	20%	80%			Net-to-Gross
Alternate Energy Impact	2.78	GJ		772	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			800	800	800	Information Only
Participants	464	539	77	154	308	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-1,746	-2,027	-290	-579	-1,158	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-1,397	-1,621	-232	-463	-926	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	358,547	416,228	59,461	118,922	237,844	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ (158,295)	$ (158,295)	$ (22,623)	$ (44,986)	$ (90,686)	
Utility Program Costs						
DSM Incentives		$ 26,950	$ 3,850	$ 7,700	$ 15,400	
Administration		$ 10,780	$ 1,540	$ 3,080	$ 6,160	
Subtotal	$ 32,501	$ 37,730	$ 5,390	$ 10,780	$ 21,560	
Participants' Net Costs						
Incremental Cost		$ (26,950)	$ (3,850)	$ (7,700)	$ (15,400)	
Subtotal	$ (23,215)	$ (26,950)	$ (3,850)	$ (7,700)	$ (15,400)	
Alternate Savings - Net						
Energy (Purchases)		$ 468,702	$ 66,957	$ 133,915	$ 267,830	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 468,702	$ 468,702	$ 66,957	$ 133,915	$ 267,830	
Net Present Benefit (Cost)	$ 301,121	$ 299,627	$42,794	$85,849	$170,984	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**33.4**		**28.8**	**28.9**	**28.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for EE E* Furnace Upgrade

PER MEASURE

Total Cost	$	600
Incentive	$	300
Participant	$	300

Annual Impact Per Measure

Energy Savings per installation	10.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	28%	72%			Net-to-Gross
Alternate Energy Impact	0.0	GJ		0	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	156	180	30	60	90	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,607	1,854	309	618	927	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	1,157	1,335	222	445	667	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	0	0	0	0	0	Other Utility Billed energy impact
lternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ 130,274	$ 130,274	$ 21,731	$ 43,211	$ 65,332	
Utility Program Costs						
DSM Incentives		$ 54,000	$ 9,000	$ 18,000	$ 27,000	
Administration		$ 3,600	$ 600	$ 1,200	$ 1,800	
Subtotal	$ 49,913	$ 57,600	$ 9,600	$ 19,200	$ 28,800	
Participants' Net Costs						
Incremental Cost		$ 54,000	$ 9,000	$ 18,000	$ 27,000	
Subtotal	$ 46,794	$ 54,000	$ 9,000	$ 18,000	$ 27,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 33,567	$ 18,674	$3,131	$6,011	$9,532	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	1.3		1.2	1.2	1.2	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 7.94		$ 7.94	$ 7.94	$ 7.94	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for EE EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	8.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	10%	90%			Net-to-Gross
Alternate Energy Impact	0.09	GJ		25	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	15	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	104	120	20	40	60	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	863	996	166	332	498	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	777	896	149	299	448	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	2,600	3,000	500	1,000	1,500	Other Utility Billed energy impact
lternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ 77,403	$ 77,403	$ 12,960	$ 25,675	$ 38,768	
Utility Program Costs						
DSM Incentives		$ 24,000	$ 4,000	$ 8,000	$ 12,000	
Administration		$ 2,400	$ 400	$ 800	$ 1,200	
Subtotal	$ 22,877	$ 26,400	$ 4,400	$ 8,800	$ 13,200	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 3,409	$ 568	$ 1,136	$ 1,704	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 3,409	$ 3,409	$ 568	$ 1,136	$ 1,704	
Net Present Benefit (Cost)	$ 57,935	$ 54,412	$9,128	$18,012	$27,272	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.5**		**3.1**	**3.0**	**3.1**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.11**		**$ 3.11**	**$ 3.11**	**$ 3.11**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for EE E * Dishwasher

PER MEASURE

Total Cost	$	50
Incentive	$	25
Participant	$	25

Annual Impact Per Measure

Energy Savings per installation	2.1	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	33%	67%		Net-to-Gross
Alternate Energy Impact	0.1	GJ	28	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	13	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	845	975	175	300	500	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,774	2,048	368	630	1,050	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	1,189	1,372	246	422	704	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	23,470	27,083	4,861	8,333	13,889	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$78.30	$77.35	$78.05	
Energy Purchases	$ 106,838	$ 106,838	$ 19,280	$ 32,649	$ 54,909	
Utility Program Costs						
DSM Incentives		$ 24,375	$ 4,375	$ 7,500	$ 12,500	
Administration		$ 61,167	$ 26,833	$ 15,167	$ 19,167	
Subtotal	$ 75,670	$ 85,542	$ 31,208	$ 22,667	$ 31,667	
Participants' Net Costs						
Incremental Cost		$ 24,375	$ 4,375	$ 7,500	$ 12,500	
Subtotal	$ 21,123	$ 24,375	$ 4,375	$ 7,500	$ 12,500	
Alternate Savings - Net						
Energy (Purchases)		$ 20,883	$ 3,748	$ 6,426	$ 10,709	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 20,883	$ 20,883	$ 3,748	$ 6,426	$ 10,709	
Net Present Benefit (Cost)	$ 30,927	$ 17,804	($12,554)	$8,907	$21,451	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.3**		**0.6**	**1.3**	**1.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 9.40**		**$ 16.69**	**$ 8.25**	**$ 7.25**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for EE E* Clothes Washer

PER MEASURE

Total Cost	$	100
Incentive	$	50
Participant	$	50

Annual Impact Per Measure

Energy Savings per installation	2.9	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	33%	67%			Net-to-Gross
Alternate Energy Impact	1.0968	GJ		305	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	14	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	586	676	113	225	338	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,699	1,960	328	653	980	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	1,138	1,313	220	437	657	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	178,475	205,955	34,427	68,550	102,977	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$82.51	$81.85	$82.39	
Energy Purchases	$ 108,006	$ 108,006	$ 18,116	$ 35,784	$ 54,106	
Utility Program Costs						
DSM Incentives		$ 33,800	$ 5,650	$ 11,250	$ 16,900	
Administration		$ 13,500	$ 2,250	$ 4,500	$ 6,750	
Subtotal	$ 40,989	$ 47,300	$ 7,900	$ 15,750	$ 23,650	
Participants' Net Costs						
Incremental Cost		$ 33,800	$ 5,650	$ 11,250	$ 16,900	
Subtotal	$ 29,290	$ 33,800	$ 5,650	$ 11,250	$ 16,900	
Alternate Savings - Net						
Energy (Purchases)		$ 166,739	$ 27,872	$ 55,498	$ 83,370	$1.208 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 166,739	$ 166,739	$ 27,872	$ 55,498	$ 83,370	
Net Present Benefit (Cost)	$ 204,467	$ 193,646	$32,438	$64,281	$96,926	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.9**		**3.4**	**3.4**	**3.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 6.80**		**$ 6.80**	**$ 6.80**	**$ 6.80**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for FS E* Furnace Upgrade

PER MEASURE

Total Cost	$	600
Incentive	$	300
Participant	$	300

Annual Impact Per Measure

Energy Savings per installation	-53.2	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%			Net-to-Gross
Alternate Energy Impact	54.0	GJ		15,000	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1,593	1,800	600	600	600	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-84,726	-95,760	-31,920	-31,920	-31,920	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-84,726	-95,760	-31,920	-31,920	-31,920	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	23,888,968	27,000,002	9,000,001	9,000,001	9,000,001	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ (9,342,101)	$ (9,342,101)	$ (3,117,818)	$ (3,099,833)	$ (3,124,450)	
Utility Program Costs						
DSM Incentives		$ 540,000	$ 180,000	$ 180,000	$ 180,000	
Administration		$ 226,000	$ 98,666	$ 86,167	$ 41,167	
Subtotal	$ 680,865	$ 766,000	$ 278,666	$ 266,167	$ 221,167	
Participants' Net Costs						
Incremental Cost		$ 540,000	$ 180,000	$ 180,000	$ 180,000	
Subtotal	$ 477,779	$ 540,000	$ 180,000	$ 180,000	$ 180,000	
Alternate Savings - Net						
Energy (Purchases)		$ 38,004,891	$ 12,668,297	$ 12,668,297	$ 12,668,297	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 38,004,891	$ 38,004,891	$ 12,668,297	$ 12,668,297	$ 12,668,297	
Net Present Benefit (Cost)	$ 27,504,146	$ 27,356,790	$9,091,813	$9,122,297	$9,142,680	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**24.7**		**20.8**	**21.4**	**23.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for FS EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	-15.8	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	10%	90%		Net-to-Gross
Alternate Energy Impact	10.0	GJ	2,778	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	15	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	722	831	150	281	400	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-11,401	-13,130	-2,370	-4,440	-6,320	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-10,261	-11,817	-2,133	-3,996	-5,688	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	2,004,364	2,308,334	416,667	780,556	1,111,111	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ (1,020,379)	$ (1,020,379)	$ (185,029)	$ (343,354)	$ (491,995)	
Utility Program Costs						
DSM Incentives		$ 166,200	$ 30,000	$ 56,200	$ 80,000	
Administration		$ 160,125	$ 59,166	$ 49,292	$ 51,667	
Subtotal	$ 286,406	$ 326,325	$ 89,166	$ 105,492	$ 131,667	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 2,623,036	$ 473,472	$ 886,971	$ 1,262,592	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 2,623,036	$ 2,623,036	$ 473,472	$ 886,971	$ 1,262,592	
Net Present Benefit (Cost)	$ 1,316,251	$ 1,276,332	$199,277	$438,125	$638,930	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**5.6**		**3.2**	**5.2**	**5.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for FS Gas Cooking Range

PER MEASURE

Total Cost	$ 150			
Incentive	$ 150			
Participant	$ -			
Annual Impact Per Measure				
Energy Savings per installation	-7.8	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	40%	60%		Net-to-Gross
Alternate Energy Impact	3.1	GJ	861	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	18	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1,170	1,350	225	450	675	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-9,125	-10,530	-1,755	-3,510	-5,265	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-5,475	-6,318	-1,053	-2,106	-3,159	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	1,007,362	1,162,500	193,750	387,500	581,250	Other Utility Billed energy impact
lternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ (616,587)	$ (616,587)	$ (102,853)	$ (204,519)	$ (309,215)	
Utility Program Costs						
DSM Incentives		$ 202,500	$ 33,750	$ 67,500	$ 101,250	
Administration		$ 43,667	$ 12,833	$ 13,167	$ 17,667	
Subtotal	$ 213,849	$ 246,167	$ 46,583	$ 80,667	$ 118,917	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 981,793	$ 163,632	$ 327,264	$ 490,897	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 981,793	$ 981,793	$ 163,632	$ 327,264	$ 490,897	
Net Present Benefit (Cost)	$ 151,357	$ 119,039	$14,196	$42,078	$62,765	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	1.7		1.3	1.5	1.5	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ -		$ -	$ -	$ -	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for FS Gas Clothes Dryer

PER MEASURE

Total Cost	$	150
Incentive	$	150
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	-3.8	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	5%	95%			Net-to-Gross
Alternate Energy Impact	2.8	GJ		778	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	13	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1,170	1,350	225	450	675	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-4,445	-5,130	-855	-1,710	-2,565	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-4,223	-4,874	-812	-1,625	-2,437	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	909,875	1,050,000	175,000	350,000	525,000	Other Utility Billed energy impact
lternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

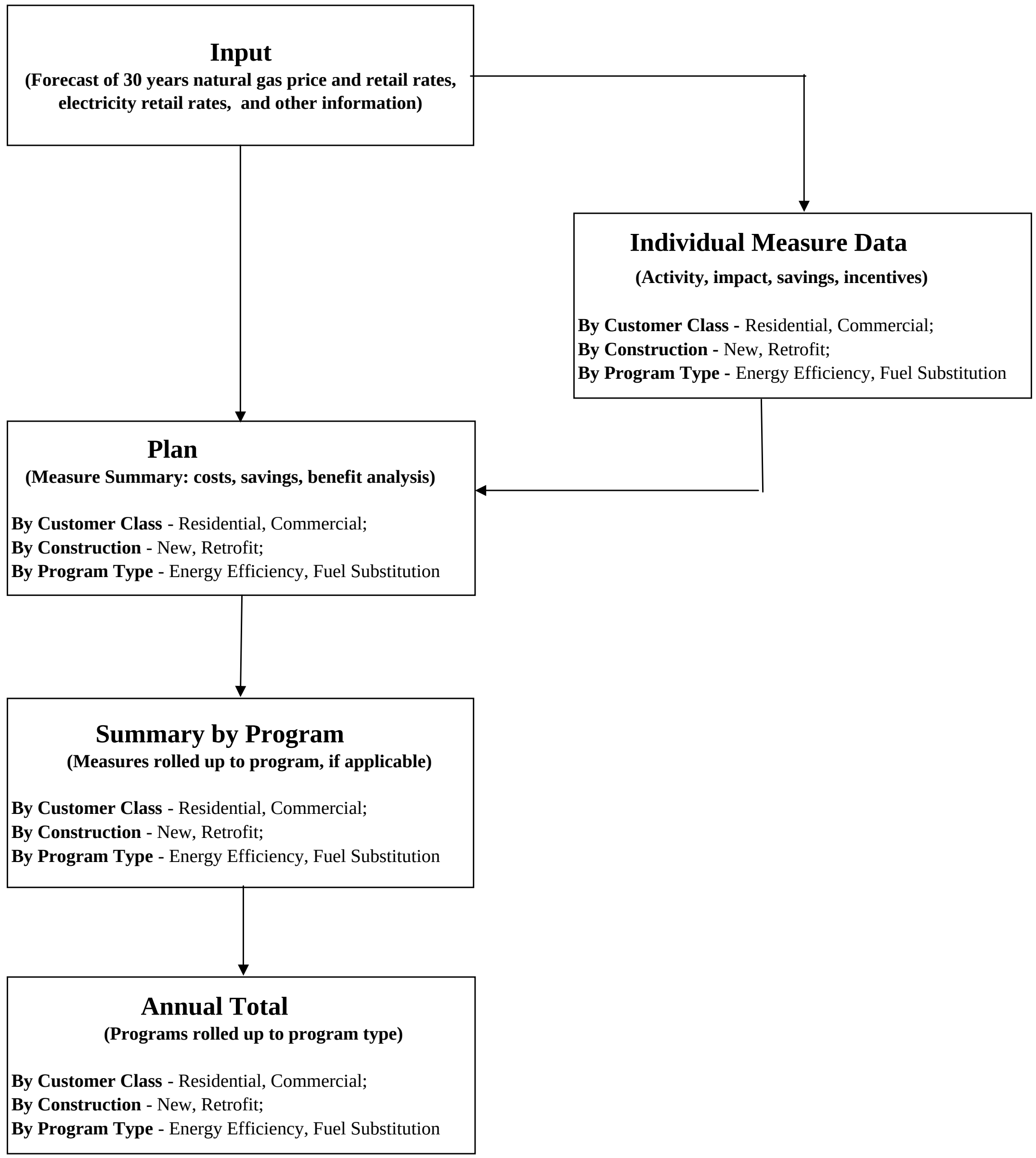
	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$78.30	$77.35	$78.05	
Energy Purchases	$ (379,445)	$ (379,445)	$ (63,602)	$ (125,652)	$ (190,190)	
Utility Program Costs						
DSM Incentives		$ 202,500	$ 33,750	$ 67,500	$ 101,250	
Administration		$ 43,667	$ 12,833	$ 13,167	$ 17,667	
Subtotal	$ 213,849	$ 246,167	$ 46,583	$ 80,667	$ 118,917	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 1,147,972	$ 191,329	$ 382,657	$ 573,986	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 1,147,972	$ 1,147,972	$ 191,329	$ 382,657	$ 573,986	
Net Present Benefit (Cost)	$ 554,677	$ 522,360	$81,143	$176,338	$264,878	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.6**		**2.7**	**3.2**	**3.2**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

Attachment 56.2 B

EXCLUDING FREE RIDERS

Table of Contents

Sheet Name	Description	MEASURE_NAME	PROGRAM NAME
Annual Total	Program Type Summary - costs, savings, and benefit analysis		
Summary by Program	Program Summary - costs, savings, and benefit analysis - annual and total		
Plan	Measures Summary - costs, savings, and benefit analysis - annual		
Input	30 years Natural Gas Price, and other inputs to the model		
EEbldg 30% Large	Measure data and benefit analysis for Efficient Design - 30% Large (New Construction)	EE Building Design (30% Large)	Efficient New Construction
EEbldg 30% Small	Measure data and benefit analysis for Efficient Design - 30% Small (New Construction)	EE Building Design (30% Small)	Efficient New Construction
EEbldg 60%	Measure data and benefit analysis for Efficient Design - 60% (New Construction)	EE Building Design (60%)	Efficient New Construction
HP Glazing Hit	Measure data and benefit analysis for HIT Windows (New Construction)	High Performance Glazing HIT	Efficient New Construction
NearCond Boiler	Measure data and benefit analysis for Near Condensing Boilers (New Construction)	Near Condensing Boiler	Boilers
Cond Boiler	Measure data and benefit analysis for Condensing Boilers (New Construction)	Condensing Boiler	Boilers
Inst DHW Heater	Measure data and benefit analysis for Instantaneous DHW Heaters (New Construction)	Instantaneous DHW Heater	Water Heating
Cond DHW Boiler	Measure data and benefit analysis for Condensing DHW Boilers (New Construction)	Condensing DHW Boiler	Water Heating
Cond DHW Heater	Measure data and benefit analysis for Condensing DHW Heaters (New Construction)	Condensing DHW Heater	Water Heating
Drainwater Heat Rec	Measure data and benefit analysis for Drainwater Heat Recovery (New Construction)	Drainwater Heat Recovery	Water Heating
Retrofit NearCondBoiler	Measure data and benefit analysis for Near Condensing Boilers (Retrofit)	Near Condensing Boiler	Boilers
Retrofit CondBoiler	Measure data and benefit analysis for Condensing Boilers (Retrofit)	Condensing Boiler	Boilers
Retrofit Bldg Re-Comm	Measure data and benefit analysis for Building Recommissioning (Retrofit)	Building Recommissioning	Building Recommissioning
Retrofit NextGenBAS	Measure data and benefit analysis for Next Generation BAS (Retrofit)	Next Generation Building Automation System	Next Generation Building Automation System
Retrofit DemCtlVent (Large)	Measure data and benefit analysis for Demand Ctl Vent. - Large (Retrofit)	Demand Control Ventilation (Large)	Demand Control Ventilation
Retrofit DemCtlVent (Med)	Measure data and benefit analysis for Demand Ctl Vent. - Medium (Retrofit)	Demand Control Ventilation (Med)	Demand Control Ventilation
Retrofit HE Roof Top	Measure data and benefit analysis for HE Rooftop units (Retrofit)	High Efficiency Roof Top Unit	High Efficiency Roof Top Unit
Retrofit Inst DHW Heater	Measure data and benefit analysis for Instantaneous DHW Heaters (Retrofit)	Instantaneous DHW Heater	Water Heating
Retrofit Cond DHW Boiler	Measure data and benefit analysis for Condensing DHW Boilers (Retrofit)	Condensing DHW Boiler	Water Heating
Retrofit Cond DHW Heater	Measure data and benefit analysis for Condensing DHW Heaters (Retrofit)	Condensing DHW Heater	Water Heating


Input
(Forecast of 30 years natural gas price and retail rates, electricity retail rates, and other information)
Individual Measure Data
(Activity, impact, savings, incentives)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Plan
(Measure Summary: costs, savings, benefit analysis)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Summary by Program
(Measures rolled up to program, if applicable)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Annual Total
(Programs rolled up to program type)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution

TERASEN GAS INC

		PROGRAM									ALTERNATE	
		COSTS ($000)							SAVINGS (GJ)		Impact	
		Utility									Energy	Capacity
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW
2008												
COMMERCIAL:												
New Construction	51	1,136	471	1,607	1,234	2,842	57%	43%	26,902	26,902	2,994	-
Retrofit	198	2,878	818	3,696	2,878	6,575	56%	44%	133,951	133,951	7,650	-
2008 Total Commercial	**249**	**4,014**	**1,289**	**5,303**	**4,113**	**9,416**	**56%**	**44%**	**160,852**	**160,852**	**10,644**	**-**
2009												
COMMERCIAL:												
New Construction	86	2,158	462	2,619	2,361	4,980	53%	47%	48,009	48,009	6,163	-
Retrofit	315	3,802	1,181	4,983	3,802	8,785	57%	43%	190,383	190,383	10,350	-
2009 Total Commercial	**401**	**5,960**	**1,643**	**7,602**	**6,163**	**13,765**	**55%**	**45%**	**238,392**	**238,392**	**16,513**	**-**
2010												
COMMERCIAL:												
New Construction	123	3,408	710	4,117	3,747	7,864	52%	48%	71,755	71,755	10,336	-
Retrofit	441	5,002	1,841	6,843	5,002	11,846	58%	42%	255,033	255,033	17,550	-
2010 Total Commercial	**564**	**8,410**	**2,551**	**10,961**	**8,749**	**19,710**	**56%**	**44%**	**326,789**	**326,789**	**27,886**	**-**
2008 - 2010 (NPV 2007)												
COMMERCIAL:												
New Construction	224	5,759	1,430	7,189	6,308	13,497	53%	47%	126,321	126,321	16,710	-
Retrofit	824	10,145	3,317	13,462	10,145	23,606	57%	43%	502,218	502,218	30,677	-
2008 - 2010 Total Commercial	**1,049**	**15,904**	**4,746**	**20,650**	**16,453**	**37,104**	**56%**	**44%**	**628,540**	**628,540**	**47,387**	**-**

	NET PRESENT VALUE									BENEFIT/COST						
	Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings				Participant					
	($/GJ)	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	Natural Gas Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2008																
COMMERCIAL:																
New Construction	5.2	2,968	4,975	3,562	415	2,136	311,186	38,271	-	1.8	1,234	6,113	5.0	0.6	2.8	5,101
Retrofit	2.5	13,896	7,320	16,727	1,949	3,142	1,465,646	56,305	-	3.8	2,878	21,818	7.6	0.7	3.2	14,642
2008 Total Commercial	**3.0**	**16,864**	**12,295**	**20,290**	**2,363**	**5,277**	**1,776,832**	**94,576**	**-**	**3.2**	**4,113**	**27,930**	**6.8**	**0.7**	**3.1**	**19,743**
2009																
COMMERCIAL:																
New Construction	4.7	5,682	10,242	6,369	783	4,396	556,337	78,784	-	2.2	2,361	11,548	4.9	0.6	3.2	10,944
Retrofit	2.4	20,739	9,903	23,479	2,898	4,251	2,059,100	76,177	-	4.2	3,802	30,627	8.1	0.7	3.5	21,857
2009 Total Commercial	**2.9**	**26,421**	**20,145**	**29,848**	**3,680**	**8,647**	**2,615,437**	**154,960**	**-**	**3.5**	**6,163**	**42,175**	**6.8**	**0.7**	**3.4**	**32,801**
2010																
COMMERCIAL:																
New Construction	4.9	8,586	17,176	9,537	1,219	7,373	832,961	132,127	-	2.1	3,747	18,129	4.8	0.6	3.3	17,898
Retrofit	2.5	27,325	16,792	30,788	3,972	7,208	2,703,560	129,170	-	4.0	5,002	41,968	8.4	0.7	3.7	32,271
2010 Total Commercial	**3.1**	**35,911**	**33,968**	**40,325**	**5,191**	**14,580**	**3,536,521**	**261,296**	**-**	**3.3**	**8,749**	**60,097**	**6.9**	**0.7**	**3.5**	**50,169**
2008 - 2010 (NPV 2007)																
COMMERCIAL:																
New Construction	4.2	17,235	32,394	19,469	2,417	13,904	1,700,484	249,182	-	2.4	6,308	35,790	5.7	0.6	3.7	36,131
Retrofit	2.2	61,961	34,015	70,994	8,818	14,600	6,228,306	261,651	-	4.6	10,145	94,413	9.3	0.7	4.1	72,369
2008 - 2010 Total Commercial	**2.6**	**79,196**	**66,408**	**90,463**	**11,235**	**28,504**	**7,928,790**	**510,833**	**-**	**3.8**	**16,453**	**130,203**	**7.9**	**0.7**	**3.9**	**108,500**

TERASEN GAS INC

		PROGRAM									ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings					Participant					
		Utility									Energy	Capacity	($/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
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2008																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	5	706	160	866	805	1,671	52%	48%	5,486	5,486	2,994	-	13	627	4,975	750	87	2,136	65,406	38,271	-	0.7	805	2,973	3.7	0.4	3.4	3,931
Boilers	13	319	173	492	319	812	61%	39%	11,050	11,050	-	-	4	1,262	0	1,511	176	0	131,749	-	-	2.6	319	1,687	5.3	0.6	1.6	450
Water Heating	33	110	139	249	110	359	69%	31%	10,366	10,366	-	-	2	1,079	0	1,301	152	0	114,031	-	-	4.3	110	1,452	13.2	0.7	3.0	720
Subtotal New Constuction	**51**	**1,136**	**471**	**1,607**	**1,234**	**2,842**	**57%**	**43%**	**26,902**	**26,902**	**2,994**	-	**5**	**2,968**	**4,975**	**3,562**	**415**	**2,136**	**311,186**	**38,271**	-	**1.8**	**1,234**	**6,113**	**5.0**	**0.6**	**2.8**	**5,101**
Retrofit																												
Boilers	80	1,900	177	2,077	1,900	3,977	52%	48%	80,790	80,790	-	-	2	9,227	0	11,051	1,286	0	963,258	-	-	4.4	1,900	12,337	6.5	0.7	2.3	5,250
Building Recommissioning	15	480	195	675	480	1,155	58%	42%	14,625	14,625	6,750	-	6	932	6,458	1,152	134	2,772	103,927	49,681	-	1.4	480	4,058	8.5	0.5	6.4	6,236
Next Generation Building Automa	4	160	59	219	160	379	58%	42%	1,948	1,948	900	-	16	124	861	153	18	370	13,843	6,624	-	0.6	160	541	3.4	0.3	2.6	606
Demand Control Ventilation	40	152	167	319	152	471	68%	32%	13,692	13,692	-	-	3	1,160	0	1,423	167	0	126,715	-	-	3.6	152	1,590	10.5	0.7	2.5	689
High Efficiency Roof Top Unit	4	18	46	64	18	82	78%	22%	706	706	-	-	8	71	0	87	10	0	7,624	-	-	1.1	18	97	5.4	0.5	0.9	(10)
Water Heating	55	169	175	344	169	512	67%	33%	22,190	22,190	-	-	1	2,382	0	2,862	333	0	250,280	-	-	6.9	169	3,195	19.0	0.7	4.7	1,870
Subtotal Retrofit	**198**	**2,878**	**818**	**3,696**	**2,878**	**6,575**	**56%**	**44%**	**133,951**	**133,951**	**7,650**	-	**3**	**13,896**	**7,320**	**16,727**	**1,949**	**3,142**	**1,465,646**	**56,305**	-	**3.8**	**2,878**	**21,818**	**7.6**	**0.7**	**3.2**	**14,642**
2008 Total Commercial	**249**	**4,014**	**1,289**	**5,303**	**4,113**	**9,416**	**56%**	**44%**	**160,852**	**160,852**	**10,644**	-	**3**	**16,864**	**12,295**	**20,290**	**2,363**	**5,277**	**1,776,832**	**94,576**	-	**3.2**	**4,113**	**27,930**	**6.8**	**0.7**	**3.1**	**19,743**
2009																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	11	1,455	204	1,658	1,658	3,316	50%	50%	11,454	11,454	6,163	-	12	1,405	10,242	1,567	192	4,396	136,566	78,784	-	0.8	1,658	6,155	3.7	0.4	3.5	8,331
Boilers	18	492	116	609	492	1,101	55%	45%	16,620	16,620	-	-	3	2,038	0	2,273	279	0	198,160	-	-	3.3	492	2,552	5.2	0.7	1.9	937
Water Heating	57	211	141	352	211	563	63%	37%	19,935	19,935	-	-	2	2,239	0	2,529	312	0	221,611	-	-	6.4	211	2,841	13.5	0.8	4.0	1,676
Subtotal New Constuction	**86**	**2,158**	**462**	**2,619**	**2,361**	**4,980**	**53%**	**47%**	**48,009**	**48,009**	**6,163**	-	**5**	**5,682**	**10,242**	**6,369**	**783**	**4,396**	**556,337**	**78,784**	-	**2.2**	**2,361**	**11,548**	**4.9**	**0.6**	**3.2**	**10,944**
Retrofit																												
Boilers	93	2,254	210	2,464	2,254	4,718	52%	48%	95,139	95,139	-	-	2	11,669	0	13,013	1,596	0	1,134,341	-	-	4.7	2,254	14,609	6.5	0.8	2.5	6,951
Building Recommissioning	20	640	237	877	640	1,517	58%	42%	19,500	19,500	9,000	-	6	1,261	8,611	1,536	195	3,696	138,570	66,241	-	1.4	640	5,427	8.5	0.5	6.5	8,356
Next Generation Building Automa	6	240	71	311	240	551	56%	44%	2,922	2,922	1,350	-	15	189	1,292	230	29	554	20,764	9,936	-	0.6	240	814	3.4	0.3	2.7	929
Demand Control Ventilation	80	304	280	584	304	888	66%	34%	27,384	27,384	-	-	2	2,414	0	2,846	357	0	253,430	-	-	4.1	304	3,203	10.5	0.7	2.7	1,526
High Efficiency Roof Top Unit	6	27	43	70	27	97	72%	28%	1,058	1,058	-	-	6	113	0	130	16	0	11,436	-	-	1.6	27	146	5.4	0.6	1.2	16
Water Heating	110	337	340	677	337	1,014	218%	82%	44,380	44,380	-	-	12	5,092	0	5,724	704	0	500,559	-	-	7.5	337	6,428	19.1	0.8	5.0	4,078
Subtotal Retrofit	**315**	**3,802**	**1,181**	**4,983**	**3,802**	**8,785**	**57%**	**43%**	**190,383**	**190,383**	**10,350**	-	**2**	**20,739**	**9,903**	**23,479**	**2,898**	**4,251**	**2,059,100**	**76,177**	-	**4.2**	**3,802**	**30,627**	**8.1**	**0.7**	**3.5**	**21,857**
2009 Total Commercial	**401**	**5,960**	**1,643**	**7,602**	**6,163**	**13,765**	**55%**	**45%**	**238,392**	**238,392**	**16,513**	-	**3**	**26,421**	**20,145**	**29,848**	**3,680**	**8,647**	**2,615,437**	**154,960**	-	**3.5**	**6,163**	**42,175**	**6.8**	**0.7**	**3.4**	**32,801**
2010																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	19	2,431	342	2,773	2,770	5,543	50%	50%	20,062	20,062	10,336	-	12	2,483	17,176	2,744	350	7,373	239,200	132,127	-	0.9	2,770	10,466	3.8	0.5	3.5	14,116
Boilers	23	665	162	827	665	1,493	55%	45%	22,190	22,190	-	-	3	2,746	0	3,035	387	0	264,571	-	-	3.3	665	3,422	5.1	0.7	1.8	1,253
Water Heating	81	312	206	517	312	829	62%	38%	29,503	29,503	-	-	2	3,357	0	3,758	483	0	329,191	-	-	6.5	312	4,240	13.6	0.8	4.1	2,528
Subtotal New Constuction	**123**	**3,408**	**710**	**4,117**	**3,747**	**7,864**	**52%**	**48%**	**71,755**	**71,755**	**10,336**	-	**5**	**8,586**	**17,176**	**9,537**	**1,219**	**7,373**	**832,961**	**132,127**	-	**2.1**	**3,747**	**18,129**	**4.8**	**0.6**	**3.3**	**17,898**
Retrofit																												
Boilers	105	2,565	289	2,854	2,565	5,419	53%	47%	107,955	107,955	-	-	2	13,360	0	14,766	1,882	0	1,287,146	-	-	4.7	2,565	16,648	6.5	0.8	2.5	7,941
Building Recommissioning	35	1,120	423	1,543	1,120	2,663	58%	42%	34,125	34,125	15,750	-	6	2,211	15,070	2,687	364	6,468	242,497	115,921	-	1.4	1,120	9,520	8.5	0.5	6.5	14,617
Next Generation Building Automa	8	320	118	438	320	758	58%	42%	3,896	3,896	1,800	-	16	252	1,722	307	42	739	27,685	13,248	-	0.6	320	1,088	3.4	0.3	2.6	1,216
Demand Control Ventilation	120	455	437	892	455	1,348	66%	34%	41,076	41,076	-	-	2	3,646	0	4,269	562	0	380,145	-	-	4.1	455	4,831	10.6	0.7	2.7	2,298
High Efficiency Roof Top Unit	8	36	69	105	36	141	75%	25%	1,411	1,411	-	-	7	153	0	173	22	0	15,248	-	-	1.4	36	196	5.4	0.5	1.1	11
Water Heating	165	506	505	1,011	506	1,516	67%	33%	66,570	66,570	-	-	12	7,703	0	8,586	1,100	0	750,839	-	-	7.6	506	9,686	19.2	0.8	5.1	6,187
Subtotal Retrofit	**441**	**5,002**	**1,841**	**6,843**	**5,002**	**11,846**	**58%**	**42%**	**255,033**	**255,033**	**17,550**	-	**3**	**27,325**	**16,792**	**30,788**	**3,972**	**7,208**	**2,703,560**	**129,170**	-	**4.0**	**5,002**	**41,968**	**8.4**	**0.7**	**3.7**	**32,271**
2010 Total Commercial	**564**	**8,410**	**2,551**	**10,961**	**8,749**	**19,710**	**56%**	**44%**	**326,789**	**326,789**	**27,886**	-	**3**	**35,911**	**33,968**	**40,325**	**5,191**	**14,580**	**3,536,521**	**261,296**	-	**3.3**	**8,749**	**60,097**	**6.9**	**0.7**	**3.5**	**50,169**
2008 - 2010 (NPV 2007)																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	30	3,937	609	4,546	4,486	9,032	50%	50%	31,683	31,683	16,710	-	10	4,514	32,394	5,061	629	13,904	441,171	249,182	-	1.0	4,486	19,595	4.4	0.5	4.1	27,876
Boilers	47	1,278	397	1,676	1,278	2,954	57%	43%	43,179	43,179	-	-	3	6,047	0	6,820	841	0	594,480	-	-	3.6	1,278	7,661	6.0	0.7	2.0	3,093
Water Heating	148	544	423	967	544	1,511	64%	36%	51,459	51,459	-	-	1	6,674	0	7,588	946	0	664,833	-	-	6.9	544	8,534	15.7	0.8	4.4	5,163
Subtotal New Constuction	**224**	**5,759**	**1,430**	**7,189**	**6,308**	**13,497**	**53%**	**47%**	**126,321**	**126,321**	**16,710**	-	**4**	**17,235**	**32,394**	**19,469**	**2,417**	**13,904**	**1,700,484**	**249,182**	-	**2.4**	**6,308**	**35,790**	**5.7**	**0.6**	**3.7**	**36,131**
Retrofit																												
Boilers	243	5,867	587	6,454	5,867	12,321	52%	48%	247,923	247,923	-	-	2	34,256	0	38,830	4,764	0	3,384,745	-	-	5.3	5,867	43,594	7.4	0.8	2.8	21,935
Building Recommissioning	60	1,932	738	2,670	1,932	4,602	58%	42%	58,867	58,867	27,169	-	6	4,404	30,140	5,375	694	12,937	484,994	231,843	-	1.6	1,932	19,006	9.8	0.5	7.5	29,942
Next Generation Building Automa	16	624	215	839	624	1,462	57%	43%	7,592	7,592	3,508	-	13	566	3,875	690	89	1,663	62,292	29,808	-	0.7	624	2,442	3.9	0.4	3.0	2,978
Demand Control Ventilation	206	783	762	1,545	783	2,328	66%	34%	70,626	70,626	-	-	2	7,219	0	8,537	1,086	0	760,290	-	-	4.7	783	9,623	12.3	0.7	3.1	4,891
High Efficiency Roof Top Unit	16	70	138	208	70	278	75%	25%	2,750	2,750	-	-	6	338	0	390	49	0	34,307	-	-	1.6	70	438	6.2	0.6	1.2	60
Water Heating	284	869	877	1,747	869	2,616	67%	33%	114,460	114,460	-	-	1	15,178	0	17,172	2,138	0	1,501,677	-	-	8.7	869	19,310	22.2	0.8	5.8	12,562
Subtotal Retrofit	**824**	**10,145**	**3,317**	**13,462**	**10,145**	**23,606**	**57%**	**43%**	**502,218**	**502,218**	**30,677**	-	**2**	**61,961**	**34,015**	**70,994**	**8,818**	**14,600**	**6,228,306**	**261,651**	-	**4.6**	**10,145**	**94,413**	**9.3**	**0.7**	**4.1**	**72,369**
2008 - 2010 Total Commercial	**1,049**	**15,904**	**4,746**	**20,650**	**16,453**	**37,104**	**56%**	**44%**	**628,540**	**628,540**	**47,387**	-	**3**	**79,196**	**66,408**	**90,463**	**11,235**	**28,504**	**7,928,790**	**510,833**	-	**3.8**	**16,453**	**130,203**	**7.9**	**0.7**	**3.9**	**108,500**

TERASEN GAS INC

		PROGRAM											ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)			LIFE	Impact		Levelized Cost	Utility Benefits		Participant Benefits (Costs)			Program Net Savings				Participant					
		Utility										Years	Energy	Capacity	($/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
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net-to-Gross	Net		MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
	Label	B	C	D	E	F	G	H	Input (program)	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Source Sheet or Calculation	Program	Program	B+C	Program	D+E	D/F	E/F	Program	Program	IxJ	Program	Program	Program	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2008																														
COMMERCIAL:																														
New Construction																														
EE Building Design (30% Large)	1	114	96	210	130	340	62%	38%	1,320	100%	1,320	25	502	-	13	151	834	181	21	358	15,737	6,415	-	0.7	130	560	4.3	0.4	2.9	644
EE Building Design (30% Small)	2	83	32	115	95	210	55%	45%	965	100%	965	25	351	-	10	110	583	132	15	250	11,510	4,481	-	1.0	95	397	4.2	0.4	3.3	483
EE Building Design (60%)	1	439	32	470	500	970	48%	52%	2,639	100%	2,639	25	2,008	-	15	301	3,337	361	42	1,432	31,463	25,668	-	0.6	500	1,835	3.7	0.4	3.7	2,668
High Performance Glazing HIT	1	70	0	70	80	150	47%	53%	562	100%	562	25	133	-	10	64	222	77	9	95	6,696	1,707	-	0.9	80	181	2.3	0.4	1.9	136
Near Condensing Boiler	8	146	17	163	146	309	53%	47%	5,480	100%	5,480	25	-	-	2	626	N/A	750	87	N/A	65,338	-	-	3.8	146	837	5.7	0.7	2.0	316
Condensing Boiler	5	173	156	329	173	502	66%	34%	5,570	100%	5,570	25	-	-	5	636	N/A	762	89	N/A	66,411	-	-	1.9	173	851	4.9	0.6	1.3	134
Instantaneous DHW Heater	15	16	97	113	16	129	88%	12%	1,098	100%	1,098	15	-	-	11	93	N/A	114	13	N/A	10,162	-	-	0.8	16	127	8.1	0.4	0.7	(36)
Condensing DHW Boiler	5	43	5	48	43	90	53%	47%	6,190	100%	6,190	25	-	-	1	707	N/A	847	99	N/A	73,803	-	-	14.9	43	945	22.2	0.8	7.9	617
Condensing DHW Heater	8	8	8	16	8	24	67%	33%	862	100%	862	10	-	-	3	55	N/A	68	8	N/A	6,128	-	-	3.4	8	76	9.5	0.7	2.3	31
Drainwater Heat Recovery	5	44	29	72	44	116	62%	38%	2,216	100%	2,216	20	-	-	3	224	N/A	272	32	N/A	23,938	-	-	3.1	44	304	6.9	0.7	1.9	108
Retrofit																														
Near Condensing Boiler	75	1,684	156	1,840	1,684	3,524	52%	48%	73,125	100%	73,125	25	-	-	2	8,351	N/A	10,002	1,164	N/A	871,868	-	-	4.5	1,684	11,166	6.6	0.7	2.4	4,828
Condensing Boiler	5	216	20	237	216	453	52%	48%	7,665	100%	7,665	25	-	-	3	875	N/A	1,048	122	N/A	91,390	-	-	3.7	216	1,170	5.4	0.7	1.9	422
Building Recommissioning	15	480	195	675	480	1,155	58%	42%	14,625	100%	14,625	10	6,750	-	6	932	6,458	1,152	134	2,772	103,927	49,681	-	1.4	480	4,058	8.5	0.5	6.4	6,236
Next Generation Building Automation System	4	160	59	219	160	379	58%	42%	1,948	100%	1,948	10	900	-	16	124	861	153	18	370	13,843	6,624	-	0.6	160	541	3.4	0.3	2.6	606
Demand Control Ventilation (Large)	20	56	94	150	56	206	73%	27%	9,740	100%	9,740	15	-	-	2	825	N/A	1,012	119	N/A	90,141	-	-	5.5	56	1,131	20.3	0.7	4.0	619
Demand Control Ventilation (Med)	20	96	73	169	96	265	64%	36%	3,952	100%	3,952	15	-	-	5	335	N/A	411	48	N/A	36,574	-	-	2.0	96	459	4.8	0.6	1.3	70
High Efficiency Roof Top Unit	4	18	46	64	18	82	78%	22%	706	100%	706	20	-	-	8	71	N/A	87	10	N/A	7,624	-	-	1.1	18	97	5.4	0.5	0.9	(10)
Instantaneous DHW Heater	20	21	60	81	21	102	79%	21%	1,464	100%	1,464	15	-	-	6	124	N/A	152	18	N/A	13,549	-	-	1.5	21	170	8.1	0.5	1.2	22
Condensing DHW Boiler	15	128	45	173	128	300	58%	43%	18,570	100%	18,570	25	-	-	1	2,121	N/A	2,540	296	N/A	221,410	-	-	12.3	128	2,836	22.2	0.8	7.1	1,821
Condensing DHW Heater	20	20	70	90	20	110	82%	18%	2,156	100%	2,156	10	-	-	6	137	N/A	170	20	N/A	15,321	-	-	1.5	20	190	9.5	0.5	1.2	27
2008																														
Total Commercial	249	4,014	1,289	5,303	4,113	9,416	56%	44%	160,852		160,852		10,644	-	3	16,864	12,295	20,290	2,363	5,277	1,776,832	94,576	-	3.2	4,113	27,930	6.8	0.7	3.1	19,743
2009																														
COMMERCIAL:																														
New Construction																														
EE Building Design (30% Large)	2	228	99	327	260	587	56%	44%	2,640	100%	2,640	25	1,004	-	10	324	1,668	361	44	716	31,473	12,831	-	1.0	260	1,121	4.3	0.5	3.4	1,405
EE Building Design (30% Small)	5	208	58	267	238	504	53%	47%	2,413	100%	2,413	25	876	-	9	296	1,456	330	40	625	28,774	11,203	-	1.1	238	996	4.2	0.5	3.5	1,248
EE Building Design (60%)	2	878	47	924	1,000	1,924	48%	52%	5,278	100%	5,278	25	4,016	-	15	647	6,674	722	89	2,865	62,926	51,336	-	0.7	1,000	3,675	3.7	0.4	3.8	5,397
High Performance Glazing HIT	2	140	0	140	160	300	47%	53%	1,123	100%	1,123	25	267	-	10	138	444	154	19	190	13,393	3,413	-	1.0	160	363	2.3	0.5	1.9	281
Near Condensing Boiler	8	146	17	163	146	309	53%	47%	5,480	100%	5,480	25	-	-	2	672	N/A	750	92	N/A	65,338	-	-	4.1	146	841	5.7	0.7	2.2	363
Condensing Boiler	10	346	100	446	346	792	56%	44%	11,140	100%	11,140	25	-	-	3	1,366	N/A	1,524	187	N/A	132,822	-	-	3.1	346	1,711	4.9	0.7	1.7	575
Instantaneous DHW Heater	25	26	84	110	26	137	81%	19%	1,830	100%	1,830	15	-	-	7	161	N/A	190	24	N/A	16,936	-	-	1.5	26	214	8.2	0.5	1.2	25
Condensing DHW Boiler	10	85	10	95	85	180	53%	47%	12,380	100%	12,380	25	-	-	1	1,518	N/A	1,693	208	N/A	147,607	-	-	16.0	85	1,901	22.4	0.8	8.4	1,338
Condensing DHW Heater	12	12	12	24	12	36	67%	33%	1,294	100%	1,294	10	-	-	3	84	N/A	102	13	N/A	9,192	-	-	3.5	12	115	9.6	0.7	2.3	48
Drainwater Heat Recovery	10	88	35	123	88	210	58%	42%	4,431	100%	4,431	20	-	-	3	475	N/A	544	67	N/A	47,876	-	-	3.9	88	611	7.0	0.7	2.3	265
Retrofit																														
Near Condensing Boiler	85	1,908	177	2,085	1,908	3,994	52%	48%	82,875	100%	82,875	25	-	-	2	10,165	N/A	11,336	1,390	N/A	988,118	-	-	4.9	1,908	12,726	6.7	0.8	2.5	6,171
Condensing Boiler	8	346	33	379	346	725	52%	48%	12,264	100%	12,264	25	-	-	3	1,504	N/A	1,677	206	N/A	146,224	-	-	4.0	346	1,883	5.4	0.7	2.1	780
Building Recommissioning	20	640	237	877	640	1,517	58%	42%	19,500	100%	19,500	10	9,000	-	6	1,261	8,611	1,536	195	3,696	138,570	66,241	-	1.4	640	5,427	8.5	0.5	6.5	8,356
Next Generation Building Automation System	6	240	71	311	240	551	56%	44%	2,922	100%	2,922	10	1,350	-	15	189	1,292	230	29	554	20,764	9,936	-	0.6	240	814	3.4	0.3	2.7	929
Demand Control Ventilation (Large)	40	112	147	258	112	370	70%	30%	19,480	100%	19,480	15	-	-	1	1,717	N/A	2,024	254	N/A	180,281	-	-	6.6	112	2,278	20.4	0.8	4.6	1,347
Demand Control Ventilation (Med)	40	192	134	326	192	518	63%	37%	7,904	100%	7,904	15	-	-	4	697	N/A	821	103	N/A	73,149	-	-	2.1	192	924	4.8	0.6	1.3	179
High Efficiency Roof Top Unit	6	27	43	70	27	97	72%	28%	1,058	100%	1,058	20	-	-	6	113	N/A	130	16	N/A	11,436	-	-	1.6	27	146	5.4	0.6	1.2	16
Instantaneous DHW Heater	40	42	120	162	42	204	79%	21%	2,928	100%	2,928	15	-	-	6	258	N/A	304	38	N/A	27,098	-	-	1.6	42	342	8.2	0.6	1.3	54
Condensing DHW Boiler	30	255	90	345	255	600	58%	43%	37,140	100%	37,140	25	-	-	1	4,555	N/A	5,080	623	N/A	442,820	-	-	13.2	255	5,703	22.4	0.8	7.6	3,955
Condensing DHW Heater	40	40	130	170	40	210	81%	19%	4,312	100%	4,312	10	-	-	6	279	N/A	340	43	N/A	30,642	-	-	1.6	40	383	9.6	0.5	1.3	69
2009																														
Total Commercial	401	5,960	1,643	7,602	6,163	13,765			238,392		238,392	390	16,513	0	3	26,421	20,145	29,848	3,680	8,647	2,615,437	154,960	-	3.5	6,163	42,175	6.8	0.7	3.4	32,801
2010																														
COMMERCIAL:																														
New Construction																														
EE Building Design (30% Large)	5	570	179	749	650	1,399	54%	46%	6,599	100%	6,599	25	2,509	-	10	817	4,170	903	115	1,790	78,683	32,077	-	1.1	650	2,808	4.3	0.5	3.6	3,588
EE Building Design (30% Small)	8	333	93	427	380	807	53%	47%	3,861	100%	3,861	25	1,402	-	9	478	2,330	528	67	1,000	46,038	17,925	-	1.1	380	1,596	4.2	0.5	3.5	2,001
EE Building Design (60%)	3	1,316	70	1,386	1,500	2,886	48%	52%	7,917	100%	7,917	25	6,024	-	15	980	10,011	1,083	138	4,297	94,389	77,004	-	0.7	1,500	5,518	3.7	0.4	3.8	8,104
High Performance Glazing HIT	3	211	0	211	240	451	47%	53%	1,685	100%	1,685	25	400	-	10	209	666	230	29	286	20,089	5,120	-	1.0	240	546	2.3	0.5	1.9	423
Near Condensing Boiler	8	146	17	163	146	309	53%	47%	5,480	100%	5,480	25	-	-	2	678	N/A	750	96	N/A	65,338	-	-	4.2	146	845	5.8	0.7	2.2	369
Condensing Boiler	15	519	145	664	519	1,183	56%	44%	16,710	100%	16,710	25	-	-	3	2,068	N/A	2,286	291	N/A	199,233	-	-	3.1	519	2,577	5.0	0.7	1.7	885
Instantaneous DHW Heater	35	37	144	181	37	218	83%	17%	2,562	100%	2,562	15	-	-	8	227	N/A	266	35	N/A	23,710	-	-	1.3	37	301	8.2	0.5	1.0	10
Condensing DHW Boiler	15	128	15	143	128	270	53%	47%	18,570	100%	18,570	25	-	-	1	2,298	N/A	2,540	324	N/A	221,410	-	-	16.1	128	2,864	22.5	0.9	8.5	2,028
Condensing DHW Heater	16	16	16	32	16	48	67%	33%	1,725	100%	1,725	10	-	-	3	112	N/A	136	18	N/A	12,257	-	-	3.5	16	154	9.6	0.7	2.3	64
Drainwater Heat Recovery	15	131	31	162	131	293	55%	45%	6,647	100%	6,647	20	-	-	2	719	N/A	816	105	N/A	71,814	-	-	4.4	131	921	7.0	0.7	2.5	426
Retrofit																														
Near Condensing Boiler	95	2,133	248	2,381	2,133	4,513	53%	47%	92,625	100%	92,625	25	-	-	2	11,463	N/A	12,669	1,614	N/A	1,104,367	-	-	4.8	2,133	14,284	6.7	0.8	2.5	6,950
Condensing Boiler	10	433	41	473	433	906	52%	48%	15,330	100%	15,330	25	-	-	3	1,897	N/A	2,097	267	N/A	182,779	-	-	4.0	433	2,364	5.5	0.7	2.1	991
Building Recommissioning	35	1,120	423	1,543	1,120	2,663	58%	42%	34,125	100%	34,125	10	15,750	-	6	2,211	15,070	2,687	364	6,468	242,497	115,921	-	1.4	1,120	9,520	8.5	0.5	6.5	14,617
Next Generation Building Automation System	8	320	118	438	320	758	58%	42%	3,896	100%	3,896	10	1,800	-	16	252	1,722	307	42	739	27,685	13,248	-	0.6	320	1,088	3.4	0.3	2.6	1,216
Demand Control Ventilation (Large)	60	167	242	410	167	577	71%	29%	29,220	100%	29,220	15	-	-	2	2,593	N/A	3,037	400	N/A	270,422	-	-	6.3	167	3,437	20.5	0.8	4.5	2,016
Demand Control Ventilation (Med)	60	288	194	482	288	770	63%	37%	11,856	100%	11,856	15	-	-	4	1,052	N/A	1,232	162	N/A	109,723	-	-	2.2	288	1,394	4.8	0.6	1.4	282
High Efficiency Roof Top Unit	8	36	69	105	36	141	75%	25%	1,411	100%	1,411	20	-	-	7	153	N/A	173	22	N/A	15,248	-	-	1.4	36	196	5.4	0.5	1.1	11
Instantaneous DHW Heater	60	63	180	243	63	306	79%	21%	4,392	100%	4,392	15	-	-	6	390	N/A	456	60	N/A	40,647	-	-	1.6	63	517	8.2	0.6	1.3	84
Condensing DHW Boiler	45	383	135	518	383	900	58%	43%	55,710	100%	55,710	25	-	-	1	6,895	N/A	7,620	971	N/A	664,230	-	-	13.3	383	8,591	22.5	0.8	7.7	5,995
Condensing DHW Heater	60	60	190	250	60	310	81%	19%	6,468	100%	6,468	10	-	-	5	419	N/A	509	69	N/A	45,962	-	-	1.7	60	578	9.6	0.6	1.4	109
2010																														
Total Commercial	564	8,410	2,551	10,961	8,749	19,710			326,789		326,789	390	27,886	-	3	35,911	33,968	40,325	5,191	14,580	3,536,521	261,296	-	3.3	8,749	60,097	6.9	0.7	3.5	50,169

		SHEET LABELS
	Residential	
New Construction		
	EE Building Design (30% Large)	**EnerEffBldg Large**
	EE Building Design (30% Small)	**EnerEffBldg Small**
	EE Building Design (60%)	**EEBldg 60%**
	High Performance Glazing HIT	**HP Glazing Unit**
	Near Condensing Boiler	**NearCond Boilers**
	Condensing Boiler	**Cond Boilers**
	Instantaneous DHW Heater	**Inst DHW Heaters**
	Condensing DHW Boiler	**Cond DHW Boilers**
	Condensing DHW Heater	**Cond DHW Heaters**
	Drainwater Heat Recovery	**Drainwater Heat Rec**
Retrofit		
	Near Condensing Boiler	**Retrofit NearCondBoilers**
	Condensing Boiler	**Retrofit CondBoilers**
	Building Recommissioning	**Retrofit Bldg Re-Comm**
	Next Generation Building Automation System	**Retrofit NextGenBAS**
	Demand Control Ventilation (Large)	**Retrofit DemCtlVent (Large)**
	Demand Control Ventilation (Med)	**Retrofit DemCtlVent (Med)**
	High Efficiency Roof Top Unit	**Retrofit HE Roof Top**
	Instantaneous DHW Heater	**Retrofit Inst DHW Heaters**
	Condensing DHW Boiler	**Retrofit Cond DHW Boilers**
	Condensing DHW Heater	**Retrofit Cond DHW Heaters**

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for EE Building Design (30% Large)

PER MEASURE

Total Cost	$ 260,000			
Incentive	$ 130,000		$114,084	Present Value accounts for any implementation lag
Participant	$ 130,000			

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time lag to implementation	2	Years		
Energy Savings per installation	1,504	GJ	1,320	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	2,030	GJ	501,859	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	7	8	1	2	5	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	8,978	10,559	1,320	2,640	6,599	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	8,978	10,559	1,320	2,640	6,599	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	3,413,839	4,014,873	501,859	1,003,718	2,509,296	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 1,291,230	$ 1,291,230	$ 150,738	$ 323,770	$ 816,723	
Utility Program Costs						
DSM Incentives		$ 912,670	$ 114,084	$ 228,168	$ 570,419	Including Implementation Lag
Administration		$ 373,664	$ 96,333	$ 98,666	$ 178,665	
Subtotal	$ 1,099,750	$ 1,286,334	$ 210,417	$ 326,834	$ 749,084	
Participants' Net Costs						
Incremental Cost		$ 1,040,000	$ 130,000	$ 260,000	$ 650,000	
Subtotal	$ 884,310	$ 1,040,000	$ 130,000	$ 260,000	$ 650,000	
Alternate Savings - Net						
Energy (Purchases)		$ 6,672,062	$ 834,008	$ 1,668,015	$ 4,170,039	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 6,672,062	$ 6,672,062	$ 834,008	$ 1,668,015	$ 4,170,039	
Net Present Benefit (Cost)	$ 5,979,232	$ 5,636,958	$ 644,328	$ 1,404,952	$ 3,587,677	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.0**		**2.9**	**3.4**	**3.6**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 18.5**		**$ 21.6**	**$ 18.6**	**$ 17.8**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for EE Building Design (30% Small)

PER MEASURE

Total Cost	$ 95,000		
Incentive	$ 47,500	$41,684	Present Value accounts for any implementation lag
Participant	$ 47,500		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	2	Years		
Energy Savings per installation	550.0	GJ	483	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	709.0	GJ	175,280	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	13	15	2	5	8	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	6,196	7,240	965	2,413	3,861	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	6,196	7,240	965	2,413	3,861	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	2,250,269	2,629,198	350,560	876,399	1,402,239	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 884,116	$ 884,116	$ 110,247	$ 296,000	$ 477,870	
Utility Program Costs						
DSM Incentives		$ 625,267	$ 83,369	$ 208,422	$ 333,476	Including Implementation Lag
Administration		$ 183,331	$ 31,666	$ 58,333	$ 93,332	
Subtotal	$ 692,734	$ 808,598	$ 115,035	$ 266,755	$ 426,808	
Participants' Net Costs						
Incremental Cost		$ 712,500	$ 95,000	$ 237,500	$ 380,000	
Subtotal	$ 609,812	$ 712,500	$ 95,000	$ 237,500	$ 380,000	
Alternate Savings - Net						
Energy (Purchases)		$ 4,369,297	$ 582,573	$ 1,456,432	$ 2,330,292	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 4,369,297	$ 4,369,297	$ 582,573	$ 1,456,432	$ 2,330,292	
Net Present Benefit (Cost)	$ 3,950,867	$ 3,732,315	$ 482,785	$ 1,248,177	$ 2,001,354	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.0**		**3.3**	**3.5**	**3.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 17.6**		**$ 18.2**	**$ 17.5**	**$ 17.5**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for EE Building Design (60%)

PER MEASURE

Total Cost	$ 1,000,000		
Incentive	**$ 500,000**	$438,784	Present Value accounts for any implementation lag
Participant	**$ 500,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	**2**	Years		
Energy Savings per installation	**3007.0**	GJ	2,639	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**8122.0**	GJ	2,007,931	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	5	6	**1**	**2**	**3**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	13,612	15,833	2,639	5,278	7,917	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	13,612	15,833	2,639	5,278	7,917	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	10,357,307	12,047,586	2,007,931	4,015,862	6,023,793	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 1,928,441	$ 1,928,441	$ 301,375	$ 647,325	$ 979,741	
Utility Program Costs						
DSM Incentives		$ 2,632,702	$ 438,784	$ 877,567	$ 1,316,351	Including Implementation Lag
Administration		$ 148,331	**$ 31,666**	**$ 46,666**	**$ 69,999**	
Subtotal	$ 2,391,496	$ 2,781,033	$ 470,450	$ 924,233	$ 1,386,350	
Participants' Net Costs						
Incremental Cost		$ 3,000,000	$ 500,000	$ 1,000,000	$ 1,500,000	
Subtotal	$ 2,579,099	$ 3,000,000	$ 500,000	$ 1,000,000	$ 1,500,000	
Alternate Savings - Net						
Energy (Purchases)		$ 20,021,116	$ 3,336,853	$ 6,673,705	$ 10,010,558	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 20,021,116	$ 20,021,116	$ 3,336,853	$ 6,673,705	$ 10,010,558	
Net Present Benefit (Cost)	$ 16,978,961	$ 16,168,523	$ 2,667,778	$ 5,396,796	$ 8,103,949	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.4**		**3.7**	**3.8**	**3.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 30.6**		**$ 30.8**	**$ 30.6**	**$ 30.6**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for High Performance Glazing HIT

PER MEASURE

Total Cost	$ 160,000		
Incentive	$ 80,000	$70,205	Present Value accounts for any implementation lag
Participant	$ 80,000		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	2	Years		
Energy Savings per installation	640.0	GJ	562	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	540.0	GJ	133,499	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	5	6	1	2	3	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	2,897	3,370	562	1,123	1,685	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	2,897	3,370	562	1,123	1,685	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	688,617	800,997	133,499	266,999	400,498	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 410,443	$ 410,443	$ 64,144	$ 137,774	$ 208,525	
Utility Program Costs						
DSM Incentives		$ 421,232	$ 70,205	$ 140,411	$ 210,616	Including Implementation Lag
Administration		$ -	$ -	$ -	$ -	
Subtotal	$ 362,133	$ 421,232	$ 70,205	$ 140,411	$ 210,616	
Participants' Net Costs						
Incremental Cost		$ 480,000	$ 80,000	$ 160,000	$ 240,000	
Subtotal	$ 412,656	$ 480,000	$ 80,000	$ 160,000	$ 240,000	
Alternate Savings - Net						
Energy (Purchases)		$ 1,331,126	$ 221,854	$ 443,709	$ 665,563	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 1,331,126	$ 1,331,126	$ 221,854	$ 443,709	$ 665,563	
Net Present Benefit (Cost)	$ 966,779	$ 840,336	$ 135,793	$ 281,072	$ 423,472	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.2**		**1.9**	**1.9**	**1.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 22.4**		**$ 22.4**	**$ 22.4**	**$ 22.4**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Near Condensing Boiler

PER MEASURE

Total Cost	$ 36,600		
Incentive	$ 18,300	No Implementation	Present Value accounts for any implementation lag
Participant	$ 18,300		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	685.0	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%	Net-to-Gross
Alternate Energy Impact	0.0	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	21	24	8	8	8	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	14,448	16,440	5,480	5,480	5,480	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	14,448	16,440	5,480	5,480	5,480	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 1,976,192	$ 1,976,192	$ 625,855	$ 672,138	$ 678,198	
Utility Program Costs						
DSM Incentives		$ 439,200	$ 146,400	$ 146,400	$ 146,400	Including Implementation Lag
Administration		$ 49,998	$ 16,666	$ 16,666	$ 16,666	
Subtotal	$ 429,915	$ 489,198	$ 163,066	$ 163,066	$ 163,066	
Participants' Net Costs						
Incremental Cost		$ 439,200	$ 146,400	$ 146,400	$ 146,400	
Subtotal	$ 385,976	$ 439,200	$ 146,400	$ 146,400	$ 146,400	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 1,160,301	$ 1,047,794	$ 316,389	$ 362,672	$ 368,732	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.4**		**2.0**	**2.2**	**2.2**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.7**		**$ 4.7**	**$ 4.7**	**$ 4.7**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Condensing Boiler

PER MEASURE

Total Cost	$ 69,200		
Incentive	**$ 34,600**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 34,600**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	**1114.0**	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%	Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	26	30	**5**	**10**	**15**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	28,731	33,420	5,570	11,140	16,710	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	28,731	33,420	5,570	11,140	16,710	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 4,070,498	$ 4,070,498	$ 636,133	$ 1,366,354	$ 2,068,010	
Utility Program Costs						
DSM Incentives		$ 1,038,000	$ 173,000	$ 346,000	$ 519,000	Including Implementation Lag
Administration		$ 401,164	**$ 156,082**	**$ 99,833**	**$ 145,249**	
Subtotal	$ 1,245,602	$ 1,439,164	$ 329,082	$ 445,833	$ 664,249	
Participants' Net Costs						
Incremental Cost		$ 1,038,000	$ 173,000	$ 346,000	$ 519,000	
Subtotal	$ 892,368	$ 1,038,000	$ 173,000	$ 346,000	$ 519,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 1,932,528	$ 1,593,334	$ 134,051	$ 574,521	$ 884,761	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.9**		**1.3**	**1.7**	**1.7**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 6.2**		**$ 7.6**	**$ 6.0**	**$ 5.9**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Instantaneous DHW Heater

PER MEASURE

Total Cost	$ 2,100		
Incentive	$ 1,050	No Implementation	Present Value accounts for any implementation lag
Participant	$ 1,050		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	73.2	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	15	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	65	75	15	25	35	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	4,741	5,490	1,098	1,830	2,562	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	4,741	5,490	1,098	1,830	2,562	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$88.15	$88.75	
Energy Purchases	$ 481,691	$ 481,691	$ 93,001	$ 161,312	$ 227,378	
Utility Program Costs						
DSM Incentives		$ 78,750	$ 15,750	$ 26,250	$ 36,750	Including Implementation Lag
Administration		$ 325,333	$ 97,333	$ 84,000	$ 144,000	
Subtotal	$ 351,280	$ 404,083	$ 113,083	$ 110,250	$ 180,750	
Participants' Net Costs						
Incremental Cost		$ 78,750	$ 15,750	$ 26,250	$ 36,750	
Subtotal	$ 68,002	$ 78,750	$ 15,750	$ 26,250	$ 36,750	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 62,409	$ (1,142)	$ (35,832)	$ 24,812	$ 9,878	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.1**		**0.7**	**1.2**	**1.0**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 9.6**		**$ 12.7**	**$ 8.1**	**$ 9.2**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Condensing DHW Boiler

PER MEASURE

Total Cost	$ 17,000		
Incentive	$ 8,500	No Implementation	Present Value accounts for any implementation lag
Participant	$ 8,500		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	1238.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	26	30	5	10	15	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	31,929	37,140	6,190	12,380	18,570	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	31,929	37,140	6,190	12,380	18,570	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 4,523,588	$ 4,523,588	$ 706,942	$ 1,518,444	$ 2,298,202	
Utility Program Costs						
DSM Incentives		$ 255,000	$ 42,500	$ 85,000	$ 127,500	Including Implementation Lag
Administration		$ 30,000	$ 5,000	$ 10,000	$ 15,000	
Subtotal	$ 245,014	$ 285,000	$ 47,500	$ 95,000	$ 142,500	
Participants' Net Costs						
Incremental Cost		$ 255,000	$ 42,500	$ 85,000	$ 127,500	
Subtotal	$ 219,223	$ 255,000	$ 42,500	$ 85,000	$ 127,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 4,059,350	$ 3,983,588	$ 616,942	$ 1,338,444	$ 2,028,202	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**9.7**		**7.9**	**8.4**	**8.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 1.2**		**$ 1.2**	**$ 1.2**	**$ 1.2**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Condensing DHW Heater

PER MEASURE

Total Cost	$ 2,000		
Incentive	**$ 1,000**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 1,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	**107.8**	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%	Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	**10**	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	31	36	**8**	**12**	**16**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	3,361	3,881	862	1,294	1,725	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	3,361	3,881	862	1,294	1,725	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$63.74	$64.69	$64.78	
Energy Purchases	$ 250,379	$ 250,379	$ 54,969	$ 83,680	$ 111,730	
Utility Program Costs						
DSM Incentives		$ 36,000	$ 8,000	$ 12,000	$ 16,000	Including Implementation Lag
Administration		$ 36,000	**$ 8,000**	**$ 12,000**	**$ 16,000**	
Subtotal	$ 62,357	$ 72,000	$ 16,000	$ 24,000	$ 32,000	
Participants' Net Costs						
Incremental Cost		$ 36,000	$ 8,000	$ 12,000	$ 16,000	
Subtotal	$ 31,179	$ 36,000	$ 8,000	$ 12,000	$ 16,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 156,843	$ 142,379	$ 30,969	$ 47,680	$ 63,730	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.7**		**2.3**	**2.3**	**2.3**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.9**		**$ 3.9**	**$ 3.9**	**$ 3.9**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
NEW

Measure Data for Drainwater Heat Recovery

PER MEASURE

Total Cost	$ 17,500		
Incentive	$ 8,750	No Implementation	Present Value accounts for any implementation lag
Participant	$ 8,750		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	443.1	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%	Net-to-Gross
Alternate Energy Impact	0.0	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	20	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	26	30	5	10	15	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	11,428	13,293	2,216	4,431	6,647	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	11,428	13,293	2,216	4,431	6,647	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$101.17	$107.24	$108.21	
Energy Purchases	$ 1,418,538	$ 1,418,538	$ 224,152	$ 475,164	$ 719,222	
Utility Program Costs						
DSM Incentives		$ 262,500	$ 43,750	$ 87,500	$ 131,250	Including Implementation Lag
Administration		$ 94,581	$ 28,541	$ 35,416	$ 30,624	
Subtotal	$ 308,664	$ 357,081	$ 72,291	$ 122,916	$ 161,874	
Participants' Net Costs						
Incremental Cost		$ 262,500	$ 43,750	$ 87,500	$ 131,250	
Subtotal	$ 225,671	$ 262,500	$ 43,750	$ 87,500	$ 131,250	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.491 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 884,203	$ 798,957	$ 108,111	$ 264,748	$ 426,098	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.7**		**1.9**	**2.3**	**2.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.3**		**$ 4.8**	**$ 4.4**	**$ 4.1**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Near Condensing Boiler

PER MEASURE

Total Cost	$ 44,900		
Incentive	$ 22,450	No Implementation	Present Value accounts for any implementation lag
Participant	$ 22,450		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	975.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	223	255	75	85	95	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	217,377	248,625	73,125	82,875	92,625	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	217,377	248,625	73,125	82,875	92,625	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 29,979,422	$ 29,979,422	$ 8,351,392	$ 10,164,868	$ 11,463,162	
Utility Program Costs						
DSM Incentives		$ 5,724,750	$ 1,683,750	$ 1,908,250	$ 2,132,750	Including Implementation Lag
Administration		$ 581,229	$ 156,244	$ 177,076	$ 247,909	
Subtotal	$ 5,510,817	$ 6,305,979	$ 1,839,994	$ 2,085,326	$ 2,380,659	
Participants' Net Costs						
Incremental Cost		$ 5,724,750	$ 1,683,750	$ 1,908,250	$ 2,132,750	
Subtotal	$ 5,005,249	$ 5,724,750	$ 1,683,750	$ 1,908,250	$ 2,132,750	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 19,463,357	$ 17,948,693	$ 4,827,648	$ 6,171,292	$ 6,949,753	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.9**		**2.4**	**2.5**	**2.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.1**		**$ 4.0**	**$ 4.0**	**$ 4.1**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Condensing Boiler

PER MEASURE

Total Cost	$ 86,500		
Incentive	$ 43,250	No Implementation	Present Value accounts for any implementation lag
Participant	$ 43,250		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	1533.0	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%	Net-to-Gross
Alternate Energy Impact	0.0	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	20	23	5	8	10	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	30,546	35,259	7,665	12,264	15,330	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	30,546	35,259	7,665	12,264	15,330	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 4,276,837	$ 4,276,837	$ 875,397	$ 1,504,216	$ 1,897,223	
Utility Program Costs						
DSM Incentives		$ 994,750	$ 216,250	$ 346,000	$ 432,500	Including Implementation Lag
Administration		$ 93,915	$ 20,416	$ 32,666	$ 40,833	
Subtotal	$ 943,134	$ 1,088,665	$ 236,666	$ 378,666	$ 473,333	
Participants' Net Costs						
Incremental Cost		$ 994,750	$ 216,250	$ 346,000	$ 432,500	
Subtotal	$ 861,773	$ 994,750	$ 216,250	$ 346,000	$ 432,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 2,471,929	$ 2,193,422	$ 422,481	$ 779,550	$ 991,390	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.4**		**1.9**	**2.1**	**2.1**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.0**		**$ 5.0**	**$ 5.0**	**$ 5.0**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Building Recommissioning

PER MEASURE

Total Cost	$ 64,000		
Incentive	$ 32,000		No Implementation Present Value accounts for any implementation lag
Participant	$ 32,000		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	975.0	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%	Net-to-Gross
Alternate Energy Impact	1620.0	GJ	450,000 kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	10	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	60	70	15	20	35	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	58,867	68,250	14,625	19,500	34,125	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	58,867	68,250	14,625	19,500	34,125	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	27,601,898	31,500,003	6,750,001	9,000,001	15,750,001	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$63.74	$64.69	$64.78	
Energy Purchases	$ 4,404,161	$ 4,404,161	$ 932,188	$ 1,261,410	$ 2,210,563	
Utility Program Costs						
DSM Incentives		$ 2,240,000	$ 480,000	$ 640,000	$ 1,120,000	Including Implementation Lag
Administration		$ 854,161	$ 194,582	$ 236,665	$ 422,914	
Subtotal	$ 2,669,690	$ 3,094,161	$ 674,582	$ 876,665	$ 1,542,914	
Participants' Net Costs						
Incremental Cost		$ 2,240,000	$ 480,000	$ 640,000	$ 1,120,000	
Subtotal	$ 1,932,044	$ 2,240,000	$ 480,000	$ 640,000	$ 1,120,000	
Alternate Savings - Net						
Energy (Purchases)		$ 30,139,559	$ 6,458,477	$ 8,611,303	$ 15,069,779	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 30,139,559	$ 30,139,559	$ 6,458,477	$ 8,611,303	$ 15,069,779	
Net Present Benefit (Cost)	$ 29,941,986	$ 29,209,559	$ 6,236,083	$ 8,356,047	$ 14,617,429	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**7.5**		**6.4**	**6.5**	**6.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 11.0**		**$ 11.1**	**$ 10.9**	**$ 11.0**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Next Generation Building Automation System

PER MEASURE

Total Cost	$ 80,000		
Incentive	**$ 40,000**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 40,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**487.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**810.0**	GJ	225,000	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**10**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	16	18	**4**	**6**	**8**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	7,592	8,766	1,948	2,922	3,896	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	7,592	8,766	1,948	2,922	3,896	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	3,561,867	4,050,000	900,000	1,350,000	1,800,000	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$63.74	$64.69	$64.78	
Energy Purchases	$ 565,558	$ 565,558	$ 124,164	$ 189,017	$ 252,377	
Utility Program Costs						
DSM Incentives		$ 720,000	$ 160,000	$ 240,000	$ 320,000	Including Implementation Lag
Administration		$ 248,750	**$ 59,167**	**$ 71,250**	**$ 118,333**	
Subtotal	$ 838,806	$ 968,750	$ 219,167	$ 311,250	$ 438,333	
Participants' Net Costs						
Incremental Cost		$ 720,000	$ 160,000	$ 240,000	$ 320,000	
Subtotal	$ 623,572	$ 720,000	$ 160,000	$ 240,000	$ 320,000	
Alternate Savings - Net						
Energy (Purchases)		$ 3,875,086	$ 861,130	$ 1,291,695	$ 1,722,261	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 3,875,086	$ 3,875,086	$ 861,130	$ 1,291,695	$ 1,722,261	
Net Present Benefit (Cost)	$ 2,978,267	$ 2,751,894	$ 606,127	$ 929,463	$ 1,216,304	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.0**		**2.6**	**2.7**	**2.6**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 27.1**		**$ 27.4**	**$ 26.5**	**$ 27.4**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Demand Control Ventilation (Large)

PER MEASURE

Total Cost	$ 5,580		
Incentive	$ 2,790	No Implementation	Present Value accounts for any implementation lag
Participant	$ 2,790		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	487.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	15	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	103	120	20	40	60	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	50,241	58,440	9,740	19,480	29,220	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	50,241	58,440	9,740	19,480	29,220	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$88.15	$88.75	
Energy Purchases	$ 5,135,396	$ 5,135,396	$ 824,979	$ 1,717,131	$ 2,593,286	
Utility Program Costs						
DSM Incentives		$ 334,800	$ 55,800	$ 111,600	$ 167,400	Including Implementation Lag
Administration		$ 483,329	$ 94,166	$ 146,665	$ 242,498	
Subtotal	$ 704,105	$ 818,129	$ 149,966	$ 258,265	$ 409,898	
Participants' Net Costs						
Incremental Cost		$ 334,800	$ 55,800	$ 111,600	$ 167,400	
Subtotal	$ 287,827	$ 334,800	$ 55,800	$ 111,600	$ 167,400	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 4,143,464	$ 3,982,467	$ 619,213	$ 1,347,266	$ 2,015,988	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**5.2**		**4.0**	**4.6**	**4.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 2.1**		**$ 2.3**	**$ 2.1**	**$ 2.1**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Demand Control Ventilation (Med)

PER MEASURE

Total Cost	$ 9,600		
Incentive	$ 4,800	No Implementation	Present Value accounts for any implementation lag
Participant	$ 4,800		

Annual Impact Per Measure				Average Annnual Energy Savings per Measure
Time to impementation	-	Years		
Energy Savings per installation	197.6	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	15	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	103	120	20	40	60	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	20,385	23,712	3,952	7,904	11,856	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	20,385	23,712	3,952	7,904	11,856	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$88.15	$88.75	
Energy Purchases	$ 2,083,684	$ 2,083,684	$ 334,735	$ 696,725	$ 1,052,225	
Utility Program Costs						
DSM Incentives		$ 576,000	$ 96,000	$ 192,000	$ 288,000	Including Implementation Lag
Administration		$ 400,996	$ 72,833	$ 133,665	$ 194,498	
Subtotal	$ 840,611	$ 976,996	$ 168,833	$ 325,665	$ 482,498	
Participants' Net Costs						
Incremental Cost		$ 576,000	$ 96,000	$ 192,000	$ 288,000	
Subtotal	$ 495,187	$ 576,000	$ 96,000	$ 192,000	$ 288,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 747,886	$ 530,688	$ 69,902	$ 179,060	$ 281,727	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	1.6		1.3	1.3	1.4	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 7.1		$ 7.2	$ 7.1	$ 7.0	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for High Efficiency Roof Top Unit

PER MEASURE

Total Cost	$ 9,000		
Incentive	**$ 4,500**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 4,500**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**176.4**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**20**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	16	18	**4**	**6**	**8**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	2,750	3,175	706	1,058	1,411	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	2,750	3,175	706	1,058	1,411	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$101.17	$107.24	$108.21	
Energy Purchases	$ 337,594	$ 337,594	$ 71,389	$ 113,499	$ 152,707	
Utility Program Costs						
DSM Incentives		$ 81,000	$ 18,000	$ 27,000	$ 36,000	Including Implementation Lag
Administration		$ 158,083	**$ 45,500**	**$ 43,250**	**$ 69,333**	
Subtotal	$ 207,728	$ 239,083	$ 63,500	$ 70,250	$ 105,333	
Participants' Net Costs						
Incremental Cost		$ 81,000	$ 18,000	$ 27,000	$ 36,000	
Subtotal	$ 70,152	$ 81,000	$ 18,000	$ 27,000	$ 36,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.491 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 59,714	$ 17,511	$ (10,111)	$ 16,249	$ 11,374	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.2**		**0.9**	**1.2**	**1.1**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 9.4**		**$ 10.7**	**$ 8.5**	**$ 9.3**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Instantaneous DHW Heater

PER MEASURE

Total Cost	$ 2,100		
Incentive	**$ 1,050**		No Implementation Present Value accounts for any implementation lag
Participant	**$ 1,050**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	**73.2**	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%	Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	**15**	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	103	120	**20**	**40**	**60**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	7,552	8,784	1,464	2,928	4,392	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	7,552	8,784	1,464	2,928	4,392	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$88.15	$88.75	
Energy Purchases	$ 771,891	$ 771,891	$ 124,001	$ 258,098	$ 389,792	
Utility Program Costs						
DSM Incentives		$ 126,000	$ 21,000	$ 42,000	$ 63,000	Including Implementation Lag
Administration		$ 360,000	**$ 60,000**	**$ 120,000**	**$ 180,000**	
Subtotal	$ 417,814	$ 486,000	$ 81,000	$ 162,000	$ 243,000	
Participants' Net Costs						
Incremental Cost		$ 126,000	$ 21,000	$ 42,000	$ 63,000	
Subtotal	$ 108,322	$ 126,000	$ 21,000	$ 42,000	$ 63,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 245,755	$ 159,891	$ 22,001	$ 54,098	$ 83,792	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.5**		**1.2**	**1.3**	**1.3**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 7.5**		**$ 7.5**	**$ 7.5**	**$ 7.5**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Condensing DHW Boiler

PER MEASURE

Total Cost	$ 17,000		
Incentive	**$ 8,500**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 8,500**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**1238.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	77	90	**15**	**30**	**45**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	95,788	111,420	18,570	37,140	55,710	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	95,788	111,420	18,570	37,140	55,710	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$114.21	$122.65	$123.76	
Energy Purchases	$ 13,570,763	$ 13,570,763	$ 2,120,825	$ 4,555,333	$ 6,894,605	
Utility Program Costs						
DSM Incentives		$ 765,000	$ 127,500	$ 255,000	$ 382,500	Including Implementation Lag
Administration		$ 270,000	**$ 45,000**	**$ 90,000**	**$ 135,000**	
Subtotal	$ 889,789	$ 1,035,000	$ 172,500	$ 345,000	$ 517,500	
Participants' Net Costs						
Incremental Cost		$ 765,000	$ 127,500	$ 255,000	$ 382,500	
Subtotal	$ 657,670	$ 765,000	$ 127,500	$ 255,000	$ 382,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 12,023,303	$ 11,770,763	$ 1,820,825	$ 3,955,333	$ 5,994,605	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**8.8**		**7.1**	**7.6**	**7.7**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 1.4**		**$ 1.4**	**$ 1.4**	**$ 1.4**	Informational (for comparison with supply options)

TERASEN GAS INC
COMMERCIAL
RETROFIT

Measure Data for Condensing DHW Heater

PER MEASURE

Total Cost	$ 2,000		
Incentive	**$ 1,000**	No Implementation	Present Value accounts for any implementation lag
Participant	**$ 1,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	**-**	Years		
Energy Savings per installation	**107.8**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**10**	Years	Estimated lifespan of measure	

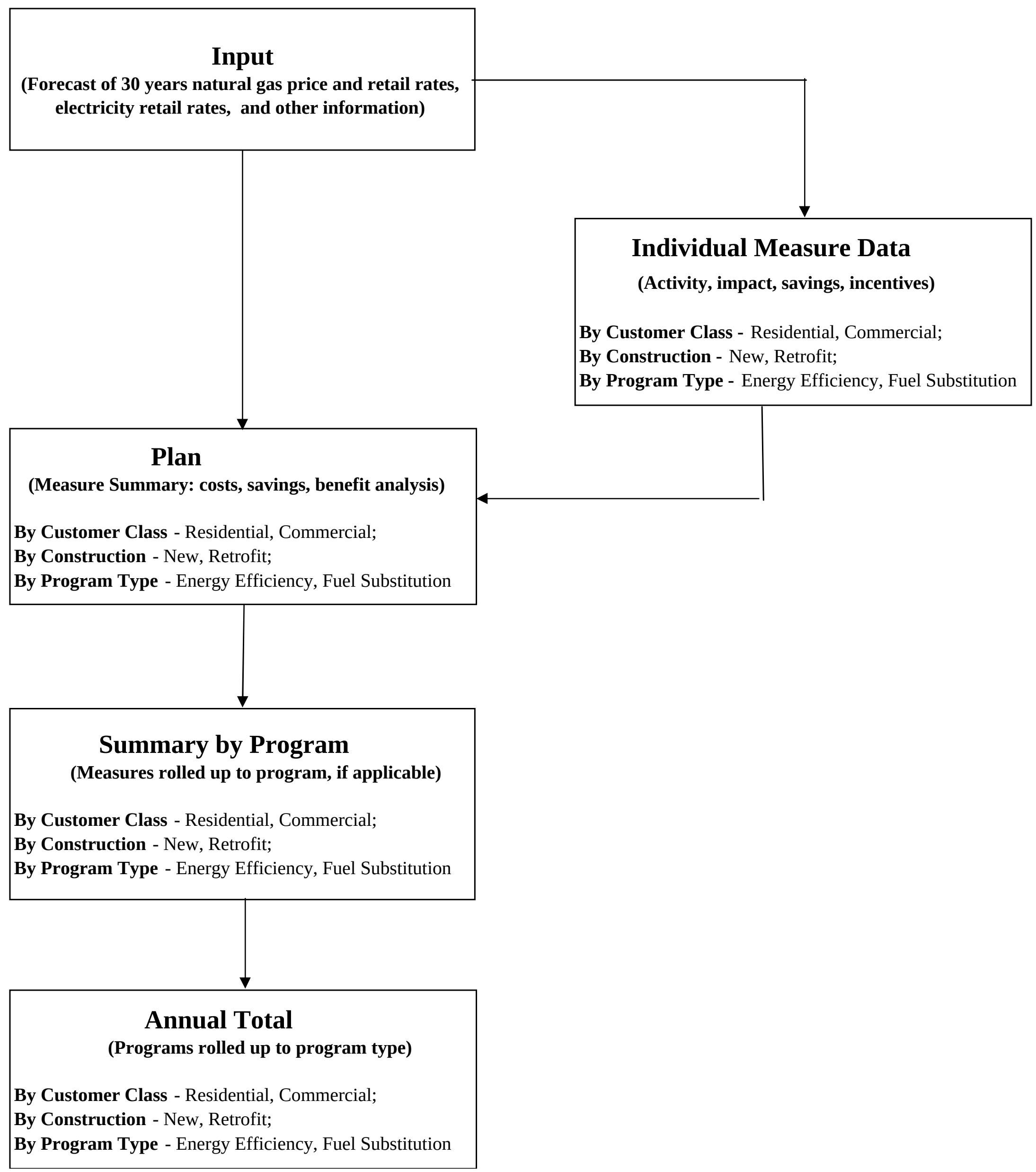
ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	103	120	**20**	**40**	**60**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	11,121	12,936	2,156	4,312	6,468	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	11,121	12,936	2,156	4,312	6,468	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$63.74	$64.69	$64.78	
Energy Purchases	$ 835,342	$ 835,342	$ 137,422	$ 278,933	$ 418,987	
Utility Program Costs						
DSM Incentives		$ 120,000	$ 20,000	$ 40,000	$ 60,000	Including Implementation Lag
Administration		$ 390,000	**$ 70,000**	**$ 130,000**	**$ 190,000**	
Subtotal	$ 439,020	$ 510,000	$ 90,000	$ 170,000	$ 250,000	
Participants' Net Costs						
Incremental Cost		$ 120,000	$ 20,000	$ 40,000	$ 60,000	
Subtotal	$ 103,164	$ 120,000	$ 20,000	$ 40,000	$ 60,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 293,158	$ 205,342	$ 27,422	$ 68,933	$ 108,987	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.5**		**1.2**	**1.3**	**1.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 6.9**		**$ 7.2**	**$ 6.9**	**$ 6.7**	Informational (for comparison with supply options)

Table of Contents

Sheet Name	Description	MEASURE NAME	PROGRAM NAME
Annual Total	Program Type Summary - costs, savings, and benefit analysis		
Summary by Program	Program Summary - costs, savings, and benefit analysis - annual and total		
Plan	Measures Summary - costs, savings, and benefit analysis - annual		
Input	30 years Natural Gas Price, and other inputs to the model		
FP	Measure data and benefit analysis for Fireplaces (New Construction)	EE EnerChoice Fireplace	EE EnerChoice Fireplace
Estar Clothes	Measure data and benefit analysis for Clothes Washers (New Construction)	EE E* Clothes Washers	EE E* Hot Water Saving Appliances
Estar Dish	Measure data and benefit analysis for Dish Washers (New Construction)	EE E* Dishwashers	EE E* Hot Water Saving Appliances
FS Range	Measure data and benefit analysis for Cooking Ranges (New Construction)	FS Gas Cooking Range	FS Gas Cooking Range
FS Dryer	Measure data and benefit analysis for Clothes Dryers (New Construction)	FS Gas Clothes Dryer	FS Gas Clothes Dryer
Retrofit FP	Measure data and benefit analysis for Fireplaces (Retrofit)	EE E* Furnace Upgrade	EE E* Furnace Upgrade
Retrofit Furnace	Measure data and benefit analysis for Furnace Upgrade (Retrofit)	EE EnerChoice Fireplace	EE EnerChoice Fireplace
Retrofit Estar Dish	Measure data and benefit analysis for Dish Washers (Retrofit)	E* Dishwasher	EE E* Hot Water Saving Appliances
Retrofit Estar Clothes	Measure data and benefit analysis for Clothes Washers (Retrofit)	E* Clothes Washer	EE E* Hot Water Saving Appliances


Input
(Forecast of 30 years natural gas price and retail rates, electricity retail rates, and other information)
Individual Measure Data
(Activity, impact, savings, incentives)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Plan
(Measure Summary: costs, savings, benefit analysis)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Summary by Program
(Measures rolled up to program, if applicable)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Annual Total
(Programs rolled up to program type)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution

TERASEN GAS INC

		PROGRAM										ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)			Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant						
		Utility										Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas				Natural Gas		TRC Net Benefits
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Rate Impact	Total Resource	($'000s)
2008																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	3,000	175	236	411	75	486	85%	15%	10,850	10,850	218	-	4.3	914	260	1,134	126	127	95,893	2,003	-	2.2	75	1,387	18.5	0.6	2.4	689
Fuel Substitution	3,900	195	164	359	-195	164	219%	-119%	-31,770	-31,770	3,883	-	FS	(3,120)	5,466	(3,887)	(431)	2,664	(325,472)	42,047	-	FS	4,318	2,859	0.7	1.1	1.7	2,182
Retrofit																												
Energy Efficiency	10,000	1,750	745	2,495	1,350	3,845	65%	35%	83,600	83,600	715	-	3.0	7,867	863	9,790	1,086	421	821,902	6,641	-	3.2	1,350	11,297	8.4	0.6	2.3	4,885
Fuel Substitution	-	-	-	-	-	- -	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Subtotals																												
Residential Energy Efficiency	13,000	1,925	981	2,906	1,425	4,331	67%	33%	94,450	94,450	933	-	3.2	8,780	1,124	10,924	1,212	548	917,795	8,645	-	**3.0**	**1,425**	**12,684**	**8.9**	**0.6**	**2.3**	**5,573**
Residential Fuel Substitution	3,900	195	164	359	-195	164	219%	-119%	-31,770	-31,770	3,883	-	FS	(3,120)	5,466	(3,887)	(431)	2,664	(325,472)	42,047	-	**FS**	**4,318**	**2,859**	**0.7**	**1.1**	**1.7**	**2,182**
2008 Residential Total	**16,900**	**2,120**	**1,145**	**3,265**	**1,230**	**4,495**	**73%**	**27%**	**62,680**	**62,680**	**4,816**	**-**	**5.5**	**5,660**	**6,590**	**7,037**	**781**	**3,212**	**592,323**	**50,692**	**-**							
2009																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	5,500	425	141	566	125	691	82%	18%	23,350	23,350	420	-	2.7	1,975	505	2,474	294	246	208,997	3,882	-	3.5	125	3,014	24.1	0.6	3.6	1,789
Fuel Substitution	5,400	270	139	409	-270	139	294%	-194%	-43,220	-43,220	5,356	-	FS	(4,217)	7,538	(5,288)	(623)	3,674	(442,774)	57,988	-	FS	5,911	3,944	0.7	1.1	1.7	3,182
Retrofit																												
Energy Efficiency	12,500	1,925	733	2,658	1,425	4,083	65%	35%	93,650	93,650	1,060	-	2.9	8,657	1,279	10,853	1,283	623	911,694	9,840	-	3.3	1,425	12,760	9.0	0.6	2.4	5,853
Fuel Substitution	-	-	-	-	-	- -	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Subtotals																												
Residential Energy Efficiency	18,000	2,350	874	3,224	1,550	4,774	68%	32%	117,000	117,000	1,480	-	2.9	10,632	1,784	13,326	1,578	869	1,120,691	13,723	-	**3.3**	**1,550**	**15,774**	**10.2**	**0.6**	**2.6**	**7,642**
Residential Fuel Substitution	5,400	270	139	409	-270	139	294%	-194%	-43,220	-43,220	5,356	-	FS	(4,217)	7,538	(5,288)	(623)	3,674	(442,774)	57,988	-	**FS**	**5,911**	**3,944**	**0.7**	**1.1**	**1.7**	**3,182**
2009 Residential Total	**23,400**	**2,620**	**1,013**	**3,633**	**1,280**	**4,913**	**74%**	**26%**	**73,780**	**73,780**	**6,835**	**-**	**5.4**	**6,415**	**9,322**	**8,038**	**955**	**4,544**	**677,918**	**71,710**	**-**							
2010																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	8,500	775	281	1,056	175	1,231	86%	14%	40,000	40,000	635	-	2.9	3,429	765	4,269	534	373	360,509	5,882	-	3.2	175	5,175	29.6	0.6	3.4	2,963
Fuel Substitution	6,900	345	219	564	-345	219	257%	-157%	-54,670	-54,670	6,828	-	FS	(5,383)	9,611	(6,689)	(824)	4,684	(560,075)	73,928	-	FS	7,513	5,029	0.7	1.1	1.7	4,009
Retrofit																												
Energy Efficiency	11,000	900	467	1,367	300	1,667	82%	18%	48,500	48,500	1,405	-	3.1	4,147	1,695	5,162	646	826	435,982	13,040	-	3.0	300	6,634	22.1	0.6	3.5	4,175
Fuel Substitution	-	-	-	-	-	- -	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Subtotals																												
Residential Energy Efficiency	19,500	1,675	747	2,422	475	2,897	84%	16%	88,500	88,500	2,040	-	3.0	7,576	2,460	9,430	1,180	1,199	796,490	18,922	-	**3.1**	**475**	**11,809**	**24.9**	**0.6**	**3.5**	**7,138**
Residential Fuel Substitution	6,900	345	219	564	-345	219	257%	-157%	-54,670	-54,670	6,828	-	FS	(5,383)	9,611	(6,689)	(824)	4,684	(560,075)	73,928	-	**FS**	**7,513**	**5,029**	**0.7**	**1.1**	**1.7**	**4,009**
2010 Residential Total	**26,400**	**2,020**	**967**	**2,987**	**130**	**3,117**	**96%**	**4%**	**33,830**	**33,830**	**8,867**	**-**	**12.6**	**2,193**	**12,071**	**2,741**	**356**	**5,883**	**236,416**	**92,850**	**-**							
2008 - 2010 (NPV 2007)																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	14,625	1,174	575	1,749	324	2,073	84%	16%	63,539	63,539	1,094	-	2.6	6,318	1,530	7,877	954	746	665,399	11,768	-	3.6	324	9,576	29.6	0.7	3.8	5,775
Fuel Substitution	14,065	703	457	1,160	(703)	457	254%	-154%	(112,634)	(112,634)	13,951	-	FS	(12,720)	22,615	(15,864)	(1,879)	11,022	(1,328,321)	173,964	-	FS	17,743	11,726	0.7	1.1	1.7	9,439
Retrofit																												
Energy Efficiency	29,380	4,069	1,725	5,794	2,762	8,556	68%	32%	200,371	200,371	2,755	-	2.7	20,670	3,838	25,804	3,015	1,870	2,169,578	29,521	-	3.6	2,762	30,690	11.1	0.7	2.9	15,952
Fuel Substitution	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Subtotals																												
Residential Energy Efficiency	**44,005**	**5,243**	**2,300**	**7,543**	**3,086**	**10,629**	**71%**	**29%**	**263,910**	**263,910**	**3,849**	**-**	**2.7**	**26,988**	**5,368**	**33,681**	**3,969**	**2,616**	**2,834,977**	**41,289**	**-**	**3.6**	**3,086**	**40,267**	**13.0**	**0.7**	**3.0**	**21,727**
Residential Fuel Substitution	**14,065**	**703**	**457**	**1,160**	**-703**	**457**	**254%**	**-154%**	**-112,634**	**-112,634**	**13,951**	**-**	**FS**	**(12,720)**	**22,615**	**(15,864)**	**(1,879)**	**11,022**	**(1,328,321)**	**173,964**	**-**	**FS**	**17,743**	**11,726**	**0.7**	**1.1**	**1.7**	**9,439**
2008 - 2010 Total Residential	**58,070**	**5,946**	**2,757**	**8,703**	**2,382**	**11,085**	**79%**	**21%**	**170,290**	**170,290**	**20,519**	**-**	**5.8**	**14,268**	**27,983**	**17,817**	**2,091**	**13,638**	**1,506,656**	**215,252**	**-**							

TERASEN GAS INC

	Participants	PROGRAM – COSTS ($000) – Utility – Incentives	PROGRAM – COSTS ($000) – Utility – Administration	PROGRAM – COSTS ($000) – Utility – Total	PROGRAM – COSTS ($000) – Participant	PROGRAM – COSTS ($000) – Total	PROGRAM – COSTS ($000) – % Utility	PROGRAM – COSTS ($000) – % Participant	PROGRAM – SAVINGS (GJ) – Gross	PROGRAM – SAVINGS (GJ) – Net	ALTERNATE – Impact – Energy MWh	ALTERNATE – Impact – Capacity kW	Levelized Cost ($/GJ)	NET PRESENT VALUE – Utility Benefits (Costs) – Program ($'000s)	NET PRESENT VALUE – Utility Benefits (Costs) – Alternate ($'000s)	NET PRESENT VALUE – Participant Benefits (Costs) – Program ($'000s)	NET PRESENT VALUE – Participant Benefits (Costs) – Carbon Tax ($'000s)	NET PRESENT VALUE – Participant Benefits (Costs) – Alternate ($'000s)	NET PRESENT VALUE – Program Net Savings – Natural Gas (GJ)	NET PRESENT VALUE – Program Net Savings – Alternate Energy (MWh)	NET PRESENT VALUE – Program Net Savings – Alternate Capacity (kW)	BENEFIT/COST – Natural Gas Utility	BENEFIT/COST – Participant – Total Costs ($'000s)	BENEFIT/COST – Participant – Total Benefits ($'000s)	BENEFIT/COST – Participant – Benefit/Cost	BENEFIT/COST – Natural Gas Rate Impact	BENEFIT/COST – Total Resource	BENEFIT/COST – TRC Net Benefits ($'000s)
2008																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	500	100	101	201	-	201	100%	0%	4,150	4,150	13	-	5	367	16	455	51	8	38,407	121	-	1.8	-	514	N/A	0.6	1.9	181
EE E* Hot Water Saving Appliances	2,500	75	134	209	75	284	74%	26%	6,700	6,700	205	-	4	547	245	679	75	119	57,486	1,882	-	2.6	75	873	11.6	0.6	2.8	508
Subtotal New Constuction Energy Efficiency	**3,000**	**175**	**236**	**411**	**75**	**486**	**85%**	**15%**	**10,850**	**10,850**	**218**	**-**	**4**	**914**	**260**	**1,134**	**126**	**127**	**95,893**	**2,003**	**-**	**2.2**	**75**	**1,387**	**18.5**	**0.6**	**2.4**	**689**
FS Gas Cooking Range	3,000	150	146	296	(150)	146	203%	-103%	(27,900)	(27,900)	3,083	-	FS	(2,740)	4,340	(3,414)	(379)	2,115	(285,826)	33,385	-	FS	3,792	2,265	0.6	1.1	1.5	1,454
FS Gas Clothes Dryer	900	45	18	63	(45)	18	350%	-250%	(3,870)	(3,870)	800	-	FS	(380)	1,126	(474)	(53)	549	(39,647)	8,662	-	FS	526	594	1.1	1.1	2.8	728
Subtotal New Construction Fuel Substitution	**3,900**	**195**	**164**	**359**	**(195)**	**164**	**219%**	**-119%**	**(31,770)**	**(31,770)**	**3,883**	**-**	**FS**	**(3,120)**	**5,466**	**(3,887)**	**(431)**	**2,664**	**(325,472)**	**42,047**	**-**	**FS**	**4,318**	**2,859**	**0.7**	**1.1**	**1.7**	**2,182**
Retrofit																												
EE E* Furnace Upgrade	4,000	1,200	377	1,577	1,200	2,777	57%	43%	55,200	55,200	-	-	3	5,421	-	6,754	749	-	565,504	-	-	3.4	1,200	7,503	6.3	0.7	2.0	2,644
EE EnerChoice Fireplace	2,000	400	224	624	0	624	100%	0%	16,600	16,600	50	-	4	1,466	63	1,822	202	31	153,628	486	-	2.3	-	2,055	N/A	0.6	2.4	905
EE E* Hot Water Saving Appliances	4,000	150	144	294	150	444	66%	34%	11,800	11,800	665	-	3	979	800	1,214	135	390	102,770	6,156	-	3.3	150	1,739	11.6	0.6	4.0	1,335
Subtotal Retrofit Energy Efficiency	**10,000**	**1,750**	**745**	**2,495**	**1,350**	**3,845**	**65%**	**35%**	**83,600**	**83,600**	**715**	**-**	**3**	**7,867**	**863**	**9,790**	**1,086**	**421**	**821,902**	**6,641**	**-**	**3.2**	**1,350**	**11,297**	**8.4**	**0.6**	**2.3**	**4,885**
Subtotal Retrofit Fuel Substitution	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	N/A	-	-	N/A	N/A	N/A	N/A
2008 Subtotal Energy Efficiency	**13,000**	**1,925**	**981**	**2,906**	**1,425**	**4,331**	**67%**	**33%**	**94,450**	**94,450**	**933**	**-**	**3**	**8,780**	**1,124**	**10,924**	**1,212**	**548**	**917,795**	**8,645**	**-**	**3.0**	**1,425**	**12,684**	**8.9**	**0.6**	**2.3**	**5,573**
2008 Subtotal Fuel Substitution	**3,900**	**195**	**164**	**359**	**-195**	**164**	**219%**	**-119%**	**(31,770)**	**(31,770)**	**3,883**	**-**	**FS**	**(3,120)**	**5,466**	**(3,887)**	**(431)**	**2,664**	**(325,472)**	**42,047**	**-**	**FS**	**4,318**	**2,859**	**0.7**	**1.1**	**1.7**	**2,182**
2008 Total Residential	**16,900**	**2,120**	**1,145**	**3,265**	**1,230**	**4,495**	**73%**	**27%**	**62,680**	**62,680**	**4,816**	**-**	**6**	**5,660**	**6,590**	**7,037**	**781**	**3,212**	**592,323**	**50,692**	**-**	**1.7**	**1,230**	**11,030**	**9.0**	**0.5**	**2.7**	**7,755**
2009																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	1,500	300	41	341	-	341	100%	0%	12,450	12,450	38	-	3	1,090	47	1,366	162	23	115,221	364	-	3.2	-	1,552	N/A	0.6	3.3	796
EE E* Hot Water Saving Appliances	4,000	125	99	224	125	349	64%	36%	10,900	10,900	382	-	2	885	457	1,107	132	223	93,777	3,518	-	3.9	125	1,462	11.7	0.7	3.8	993
Subtotal New Constuction Energy Efficiency	**5,500**	**425**	**141**	**566**	**125**	**691**	**82%**	**18%**	**23,350**	**23,350**	**420**	**-**	**3**	**1,975**	**505**	**2,474**	**294**	**246**	**208,997**	**3,882**	**-**	**3.5**	**125**	**3,014**	**24.1**	**0.6**	**3.6**	**1,789**
FS Gas Cooking Range	4,000	200	111	311	(200)	111	280%	-180%	(37,200)	(37,200)	4,111	-	FS	(3,630)	5,787	(4,551)	(536)	2,820	(381,101)	44,513	-	FS	5,088	3,020	0.6	1.2	1.5	2,046
FS Gas Clothes Dryer	1,400	70	28	98	(70)	28	350%	-250%	(6,020)	(6,020)	1,244	-	FS	(587)	1,752	(737)	(87)	854	(61,673)	13,474	-	FS	823	924	1.1	1.1	2.8	1,136
Subtotal New Construction Fuel Substitution	**5,400**	**270**	**139**	**409**	**(270)**	**139**	**294%**	**-194%**	**(43,220)**	**(43,220)**	**5,356**	**-**	**FS**	**(4,217)**	**7,538**	**(5,288)**	**(623)**	**3,674**	**(442,774)**	**57,988**	**-**	**FS**	**5,911**	**3,944**	**0.7**	**1.1**	**1.7**	**3,182**
Retrofit																												
EE E* Furnace Upgrade	4,000	1,200	377	1,577	1,200	2,777	57%	43%	55,200	55,200	-	-	3	5,386	-	6,754	796	-	565,504	-	-	3.4	1,200	7,550	6.3	0.6	1.9	2,609
EE EnerChoice Fireplace	2,500	500	203	703	0	703	100%	0%	20,750	20,750	63	-	4	1,816	79	2,277	270	38	192,034	607	-	2.6	-	2,586	N/A	0.6	2.7	1,191
EE E* Hot Water Saving Appliances	6,000	225	153	378	225	603	63%	37%	17,700	17,700	997	-	2	1,455	1,200	1,822	217	585	154,155	9,233	-	3.8	225	2,624	11.7	0.7	4.4	2,052
Subtotal Retrofit Energy Efficiency	**12,500**	**1,925**	**733**	**2,658**	**1,425**	**4,083**	**65%**	**35%**	**93,650**	**93,650**	**1,060**	**-**	**3**	**8,657**	**1,279**	**10,853**	**1,283**	**623**	**911,694**	**9,840**	**-**	**3.3**	**1,425**	**12,760**	**9.0**	**0.6**	**2.4**	**5,853**
Subtotal Retrofit Fuel Substitution	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	N/A	-	-	N/A	N/A	N/A	N/A
2009 Subtotal Energy Efficiency	**18,000**	**2,350**	**874**	**3,224**	**1,550**	**4,774**	**68%**	**32%**	**117,000**	**117,000**	**1,480**	**-**	**3**	**10,632**	**1,784**	**13,326**	**1,578**	**869**	**1,120,691**	**13,723**	**-**	**3.3**	**1,550**	**15,774**	**10.2**	**0.6**	**2.6**	**7,642**
2009 Subtotal Fuel Substitution	**5,400**	**270**	**139**	**409**	**-270**	**139**	**294%**	**-194%**	**(43,220)**	**(43,220)**	**5,356**	**-**	**FS**	**(4,217)**	**7,538**	**(5,288)**	**(623)**	**3,674**	**(442,774)**	**57,988**	**-**	**FS**	**5,911**	**3,944**	**0.7**	**1.1**	**1.7**	**3,182**
2009 Total Residential	**23,400**	**2,620**	**1,013**	**3,633**	**1,280**	**4,913**	**74%**	**26%**	**73,780**	**73,780**	**6,835**	**-**	**5**	**6,415**	**9,322**	**8,038**	**955**	**4,544**	**677,918**	**71,710**	**-**	**1.8**	**1,280**	**13,537**	**10.6**	**0.5**	**3.2**	**10,824**
2010																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	3,000	600	101	701	-	701	100%	0%	24,900	24,900	75	-	3	2,194	95	2,733	341	46	230,441	728	-	3.1	-	3,120	N/A	0.6	3.3	1,587
EE E* Hot Water Saving Appliances	5,500	175	179	354	175	529	67%	33%	15,100	15,100	560	-	3	1,235	670	1,536	193	327	130,067	5,154	-	3.5	175	2,056	11.7	0.7	3.6	1,376
Subtotal New Constuction Energy Efficiency	**8,500**	**775**	**281**	**1,056**	**175**	**1,231**	**86%**	**14%**	**40,000**	**40,000**	**635**	**-**	**3**	**3,429**	**765**	**4,269**	**534**	**373**	**360,509**	**5,882**	**-**	**3.2**	**175**	**5,175**	**29.6**	**0.6**	**3.4**	**2,963**
FS Gas Cooking Range	5,000	250	156	406	(250)	156	260%	-160%	(46,500)	(46,500)	5,139	-	FS	(4,578)	7,233	(5,689)	(701)	3,525	(476,376)	55,642	-	FS	6,390	3,775	0.6	1.1	1.5	2,499
FS Gas Clothes Dryer	1,900	95	63	158	(95)	63	251%	-151%	(8,170)	(8,170)	1,689	-	FS	(804)	2,377	(1,000)	(123)	1,159	(83,699)	18,287	-	FS	1,123	1,254	1.1	1.0	2.7	1,510
Subtotal New Construction Fuel Substitution	**6,900**	**345**	**219**	**564**	**(345)**	**219**	**257%**	**-157%**	**(54,670)**	**(54,670)**	**6,828**	**-**	**FS**	**(5,383)**	**9,611**	**(6,689)**	**(824)**	**4,684**	**(560,075)**	**73,928**	**-**	**FS**	**7,513**	**5,029**	**0.7**	**1.1**	**1.7**	**4,009**
Retrofit																												
EE E* Furnace Upgrade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE EnerChoice Fireplace	3,000	600	243	843	-	843	100%	0%	24,900	24,900	75	-	4	2,194	95	2,733	341	46	230,441	728	-	2.6	-	3,120	N/A	0.6	2.7	1,445
EE E* Hot Water Saving Appliances	8,000	300	223	523	300	823	64%	36%	23,600	23,600	1,330	-	3	1,953	1,600	2,429	305	780	205,540	12,311	-	3.7	300	3,514	11.7	0.7	4.3	2,730
Subtotal Retrofit Energy Efficiency	**11,000**	**900**	**467**	**1,367**	**300**	**1,667**	**82%**	**18%**	**48,500**	**48,500**	**1,405**	**-**	**3**	**4,147**	**1,695**	**5,162**	**646**	**826**	**435,982**	**13,040**	**-**	**3.0**	**300**	**6,634**	**22.1**	**0.6**	**3.5**	**4,175**
Subtotal Retrofit Fuel Substitution	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	N/A	-	-	N/A	N/A	N/A	N/A
2010 Subtotal Energy Efficiency	**19,500**	**1,675**	**747**	**2,422**	**475**	**2,897**	**84%**	**16%**	**88,500**	**88,500**	**2,040**	**-**	**3**	**7,576**	**2,460**	**9,430**	**1,180**	**1,199**	**796,490**	**18,922**	**-**	**3.1**	**747**	**11,809**	**15.8**	**0.6**	**3.5**	**7,138**
2010 Subtotal Fuel Substitution	**6,900**	**345**	**219**	**564**	**-345**	**219**	**257%**	**-157%**	**(54,670)**	**(54,670)**	**6,828**	**-**	**FS**	**(5,383)**	**9,611**	**(6,689)**	**(824)**	**4,684**	**(560,075)**	**73,928**	**-**	**FS**	**7,733**	**5,029**	**0.7**	**1.1**	**1.7**	**4,009**
2010 Total Residential	**26,400**	**2,020**	**967**	**2,987**	**130**	**3,117**	**96%**	**4%**	**33,830**	**33,830**	**8,867**	**-**	**13**	**2,193**	**12,071**	**2,741**	**356**	**5,883**	**236,416**	**92,850**	**-**	**0.7**	**967**	**8,980**	**9.3**	**0.4**	**4.6**	**11,147**
2008 - 2010 (NPV 2007)																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	4,251	850	215	1,065	0	1,065	100%	0%	35,283	35,283	106	-	3	3,650	158	4,555	554	77	384,069	1,214	-	3.4	-	5,185	N/A	0.6	3.6	2,743
EE E* Hot Water Saving Appliances	10,374	324	360	684	324	1,008	68%	32%	28,256	28,256	988	-	2	2,668	1,372	3,322	401	669	281,330	10,554	-	3.9	324	4,391	13.6	0.7	4.0	3,032
Subtotal New Constuction Energy Efficiency	**14,625**	**1,174**	**575**	**1,749**	**324**	**2,073**	**84%**	**16%**	**63,539**	**63,539**	**1,094**	**-**	**3**	**6,318**	**1,530**	**7,877**	**954**	**746**	**665,399**	**11,768**	**-**	**3.6**	**324**	**9,576**	**29.6**	**0.7**	**3.8**	**5,775**
FS Gas Cooking Range	10,431	522	363	885	(522)	363	244%	-144%	(97,009)	(97,009)	10,721	-	FS	(10,948)	17,360	(13,654)	(1,616)	8,461	(1,143,302)	133,540	-	FS	15,271	8,983	0.6	1.2	1.5	6,049
FS Gas Clothes Dryer	3,634	182	93	275	(182)	93	295%	-195%	(15,625)	(15,625)	3,230	-	FS	(1,772)	5,255	(2,210)	(262)	2,561	(185,018)	40,423	-	FS	2,472	2,743	1.1	1.1	2.8	3,390
Subtotal New Construction Fuel Substitution	**14,065**	**703**	**457**	**1,160**	**(703)**	**457**	**254%**	**-154%**	**(112,634)**	**(112,634)**	**13,951**	**-**	**FS**	**(12,720)**	**22,615**	**(15,864)**	**(1,879)**	**11,022**	**(1,328,321)**	**173,964**	**-**	**FS**	**17,743**	**11,726**	**0.7**	**1.1**	**1.7**	**9,439**
Retrofit																												
EE E* Furnace Upgrade	7,257	2,177	683	2,861	2,177	5,038	57%	43%	100,152	100,152	-	-	3	10,807	-	13,508	1,545	-	1,131,009	-	-	3.8	2,177	15,053	6.9	0.7	2.1	5,769
EE EnerChoice Fireplace	6,534	1,307	589	1,895	-	1,895	100%	0%	54,230	54,230	163	-	3	5,476	237	6,832	813	115	576,103	1,821	-	2.9	-	7,761	N/A	0.6	3.0	3,817
EE E* Hot Water Saving Appliances	15,589	585	453	1,038	585	1,623	64%	36%	45,988	45,988	2,591	-	2	4,387	3,601	5,465	657	1,755	462,466	27,700	-	4.2	585	7,877	13.5	0.7	4.9	6,366
Subtotal Retrofit Energy Efficiency	**29,380**	**4,069**	**1,725**	**5,794**	**2,762**	**8,556**	**68%**	**32%**	**200,371**	**200,371**	**2,755**	**-**	**3**	**20,670**	**3,838**	**25,804**	**3,015**	**1,870**	**2,169,578**	**29,521**	**-**	**3.6**	**2,762**	**30,690**	**11.1**	**0.7**	**2.9**	**15,952**
Subtotal Retrofit Fuel Substitution	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	N/A	-	-	N/A	N/A	N/A	N/A
2008-2010 Subtotal Energy Efficiency	**44,005**	**5,243**	**2,300**	**7,543**	**3,086**	**10,629**	**71%**	**29%**	**263,910**	**263,910**	**3,849**	**-**	**3**	**26,988**	**5,368**	**33,681**	**3,969**	**2,616**	**2,834,977**	**41,289**	**-**	**3.6**	**3,086**	**40,267**	**13.0**	**0.7**	**3.0**	**21,727**
2008-2010 Subtotal Fuel Substitution	**14,065**	**703**	**457**	**1,160**	**-703**	**457**	**254%**	**-154%**	**(112,634)**	**(112,634)**	**13,951**	**-**	**FS**	**(12,720)**	**22,615**	**(15,864)**	**(1,879)**	**11,022**	**(1,328,321)**	**173,964**	**-**	**FS**	**17,743**	**11,726**	**0.7**	**1.1**	**1.7**	**9,439**
2008-2010 Total Residential	**58,070**	**5,946**	**2,757**	**8,703**	**2,382**	**11,085**	**79%**	**21%**	**151,276**	**151,276**	**17,800**	**-**	**6**	**14,268**	**27,983**	**17,817**	**2,091**	**13,638**	**1,506,656**	**215,252**	**-**	**1.6**	**2,382**	**33,546**	**14.1**	**0.5**	**3.8**	**31,166**

TERASEN GAS INC

	PROGRAM: Participants	COSTS ($000) Utility: Incentives	Utility: Administration	Utility: Total	Participant	Total	% Utility	% Participant	SAVINGS (GJ): Gross	Net-to-Gross	Net	LIFE: Years	ALTERNATE Impact: Energy MWh	Capacity kW
Label	Label	B	C	D	E	F	G	H	Input (program)	J	K	L	M	N
Source Sheet or Calculation	et or Calculation	Program	Program	B+C	Program	D+E	D/F	E/F	Program	Program	IxJ	Program	Program	Program
2008														
RESIDENTIAL:														
New Construction														
EE EnerChoice Fireplace	500	100	101	201	0	201	100%	0%	4,150	100%	4,150	15	13	-
EE E* Clothes Washers	500	25	94	119	25	144	83%	17%	1,700	100%	1,700	14	150	-
EE E* Dishwashers	2,000	50	40	90	50	140	64%	36%	5,000	100%	5,000	13	56	-
FS Gas Cooking Range	3,000	150	146	296	-150	146	203%	-103%	-27,900	100%	-27,900	18	3,083	-
FS Gas Clothes Dryer	900	45	18	63	-45	18	350%	-250%	-3,870	100%	-3,870	18	800	-
Retrofit														
EE E* Furnace Upgrade	4,000	1,200	377	1,577	1,200	2,777	57%	43%	55,200	100%	55,200	18	-	-
EE EnerChoice Fireplace	2,000	400	224	624	0	624	100%	0%	16,600	100%	16,600	15	50	-
E* Dishwasher	2,000	50	104	154	50	204	76%	24%	5,000	100%	5,000	13	56	-
E* Clothes Washer	2,000	100	40	140	100	240	58%	42%	6,800	100%	6,800	14	609	-
2008 Total Residential	16,900	2,120	1,145	3,265	1,230	4,495	73%	27%	62,680		62,680		4,816	-
2009														
RESIDENTIAL:														
New Construction														
EE EnerChoice Fireplace	1,500	300	41	341	0	341	100%	0%	12,450	100%	12,450	15	38	-
EE E* Clothes Washers	1,000	50	39	89	50	139	64%	36%	3,400	100%	3,400	14	299	-
EE E* Dishwashers	3,000	75	60	135	75	210	64%	36%	7,500	100%	7,500	13	83	-
FS Gas Cooking Range	4,000	200	111	311	-200	111	280%	-180%	-37,200	100%	-37,200	18	4,111	-
FS Gas Clothes Dryer	1,400	70	28	98	-70	28	350%	-250%	-6,020	100%	-6,020	18	1,244	-
Retrofit														
EE E* Furnace Upgrade	4,000	1,200	377	1,577	1,200	2,777	57%	43%	55,200	100%	55,200	18	-	-
EE EnerChoice Fireplace	2,500	500	203	703	0	703	100%	0%	20,750	100%	20,750	15	63	-
E* Dishwasher	3,000	75	93	168	75	243	69%	31%	7,500	100%	7,500	13	83	-
E* Clothes Washer	3,000	150	60	210	150	360	58%	42%	10,200	100%	10,200	14	914	-
2009 Total Residential	23,400	2,620	1,013	3,633	1,280	4,913	74%	26%	73,780		73,780		6,835	-
2010														
RESIDENTIAL:														
New Construction														
EE EnerChoice Fireplace	3,000	600	101	701	0	701	100%	0%	24,900	100%	24,900	15	75	-
EE E* Clothes Washers	1,500	75	74	149	75	224	67%	33%	5,100	100%	5,100	14	449	-
EE E* Dishwashers	4,000	100	105	205	100	305	67%	33%	10,000	100%	10,000	13	111	-
FS Gas Cooking Range	5,000	250	156	406	-250	156	260%	-160%	-46,500	100%	-46,500	18	5,139	-
FS Gas Clothes Dryer	1,900	95	63	158	-95	63	251%	-151%	-8,170	100%	-8,170	18	1,689	-
Retrofit														
EE E* Furnace Upgrade	0	0	0	0	0	0	0%	0%	0%	0%	-	18	-	-
EE EnerChoice Fireplace	3,000	600	243	843	0	843	100%	0%	24,900	100%	24,900	15	75	-
E* Dishwasher	4,000	100	143	243	100	343	71%	29%	10,000	100%	10,000	13	111	-
E* Clothes Washer	4,000	200	80	280	200	480	58%	42%	13,600	100%	13,600	14	1,219	-
2010 Total Residential	26,400	2,020	967	2,987	130	3,117	96%	4%	33,830		33,830		8,867	-

	NET PRESENT VALUE: Levelized Cost ($/GJ)	Utility Benefits (Costs): Program ($'000s)	Utility Benefits (Costs): Alternate ($'000s)	Participant Benefits (Costs): Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Program Net Savings: Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	BENEFIT/COST: Natural Gas Utility	Participant: Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
Source Sheet or Calculation	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2008																
RESIDENTIAL:																
New Construction																
EE EnerChoice Fireplace	5	367	16	455	51	8	38,407	121	-	1.8	-	514	N/A	0.6	1.9	181
EE E* Clothes Washers	8	144	181	179	20	88	15,095	1,390	-	1.2	25	286	11.5	0.5	2.2	180
EE E* Dishwashers	2	403	64	500	55	31	42,392	492	-	4.5	50	587	11.7	0.7	3.3	327
FS Gas Cooking Range	FS	(2,740)	4,340	(3,414)	(379)	2,115	(285,826)	33,385	-	FS	3,792	2,265	0.6	1.1	1.5	1,454
FS Gas Clothes Dryer	FS	(380)	1,126	(474)	(53)	549	(39,647)	8,662	-	FS	526	594	1.1	1.1	2.8	728
Retrofit																
EE E* Furnace Upgrade	3	5,421	N/A	6,754	749	N/A	565,504	-	-	3.4	1,200	7,503	6.3	0.7	2.0	2,644
EE EnerChoice Fireplace	4	1,466	63	1,822	202	31	153,628	486	-	2.3	-	2,055	N/A	0.6	2.4	905
E* Dishwasher	4	403	64	500	55	31	42,392	492	-	2.6	50	587	11.7	0.6	2.3	263
E* Clothes Washer	2	576	736	714	79	359	60,378	5,664	-	4.1	100	1,152	11.5	0.7	5.5	1,072
2008 Total Residential	6	5,660	6,590	7,037	781	3,212	592,323	50,692	-	1.7	1,230	11,030	9.0	0.5	2.7	7,755
2009																
RESIDENTIAL:																
New Construction																
EE EnerChoice Fireplace	3	1,090	47	1,366	162	23	115,221	364	-	3.2	-	1,552	N/A	0.6	3.3	796
EE E* Clothes Washers	3	285	361	357	43	176	30,189	2,780	-	3.2	50	576	11.5	0.6	4.6	507
EE E* Dishwashers	2	600	96	750	90	47	63,588	738	-	4.4	75	887	11.8	0.7	3.3	486
FS Gas Cooking Range	FS	(3,630)	5,787	(4,551)	(536)	2,820	(381,101)	44,513	-	FS	5,088	3,020	0.6	1.2	1.5	2,046
FS Gas Clothes Dryer	FS	(587)	1,752	(737)	(87)	854	(61,673)	13,474	-	FS	823	924	1.1	1.1	2.8	1,136
Retrofit																
EE E* Furnace Upgrade	3	5,386	N/A	6,754	796	N/A	565,504	-	-	3.4	1,200	7,550	6.3	0.6	1.9	2,609
EE EnerChoice Fireplace	4	1,816	79	2,277	270	38	192,034	607	-	2.6	-	2,586	N/A	0.6	2.7	1,191
E* Dishwasher	3	600	96	750	90	47	63,588	738	-	3.6	75	887	11.8	0.7	2.9	452
E* Clothes Washer	2	855	1,104	1,071	128	538	90,568	8,496	-	4.1	150	1,737	11.6	0.7	5.4	1,600
2009 Total Residential	5	6,415	9,322	8,038	955	4,544	677,918	71,710	-	1.8	1,280	13,537	10.6	0.5	3.2	10,824
2010																
RESIDENTIAL:																
New Construction								-								
EE EnerChoice Fireplace	3	2,194	95	2,733	341	46	230,441	728	-	3.1	-	3,120	N/A	0.6	3.3	1,587
EE E* Clothes Washers	3	430	542	536	67	264	45,284	4,170	-	2.9	75	867	11.6	0.6	4.3	748
EE E* Dishwashers	2	805	128	1,000	126	62	84,783	984	-	3.9	100	1,189	11.9	0.7	3.1	628
FS Gas Cooking Range	FS	(4,578)	7,233	(5,689)	(701)	3,525	(476,376)	55,642	-	FS	6,390	3,775	0.6	1.1	1.5	2,499
FS Gas Clothes Dryer	FS	(804)	2,377	(1,000)	(123)	1,159	(83,699)	18,287	-	FS	1,123	1,254	1.1	1.0	2.7	1,510
Retrofit																
EE E* Furnace Upgrade	N/A	N/A	N/A	N/A	N/A	N/A	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE EnerChoice Fireplace	4	2,194	95	2,733	341	46	230,441	728	-	2.6	-	3,120	N/A	0.6	2.7	1,445
E* Dishwasher	3	805	128	1,000	126	62	84,783	984	-	3.3	100	1,189	11.9	0.6	2.7	589
E* Clothes Washer	2	1,148	1,473	1,428	179	718	120,757	11,327	-	4.1	200	2,325	11.6	0.7	5.5	2,140
2010 Total Residential	13	2,193	12,071	2,741	356	5,883	236,416	92,850	-	0.7	130	8,980	69.1	0.4	4.6	11,147

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
3														
4			**Year**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
5			Units											
6		**NATURAL GAS**												
7		Incremental Cost of Gas (nominal)	$ Per GJ	$10.43	$9.02	$8.76	$8.61	$8.08	$9.27	$7.96	$8.41	$9.52	$9.23	$9.27
8	1		*Year*	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
9	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
10	3	Incremental Cost of Gas (Real)		$10.43	$9.02	$8.76	$8.61	$8.08	$9.27	$7.96	$8.41	$9.52	$9.23	$9.27
11	4	Net Present Value -2008			$17.69	$24.88	$31.52	$37.35	$43.61	$48.66	$53.64	$58.93	$63.74	$68.26
12	5	Net Present Value -2009				$16.14	$23.22	$29.44	$36.13	$41.51	$46.83	$52.48	$57.61	$62.44
13	6	Net Present Value -2010					$15.76	$22.40	$29.54	$35.29	$40.97	$47.00	$52.48	$57.63
14														
15														
16		**ELECTRICITY**												
17		Incremental Cost of Elec	$ Per kWh	$0.13										
18		Incremental Cost of E Capacity	$ Per kW	$170.00										
19														
20														
21														
22	**RETAIL**													
23				Rate	Customers		789,928	Total Customers in BC		80,000	Total Residential and Commercial Customers on VI			
24		Residential Retail			*000's*									
25		**TGI**	$ Per MJ	$0.0113	640		712,304	Total Residential Customers in BC						
26		**TGVI**	$ Per MJ	$0.0137	72									
27		**Electricity**	$ Per MJ	$0.0176										
28		**Electricity**	$ per kWh	$0.0634	1,511		1,511,435	Total BCH Residential Customers in BC				89%		
29		**Electricity**	$ per kW per year											
30		Commercial Retail												
31		**TGI**	$ Per MJ	$0.0107	78		77,624	Total Commercial Customers in BC						
32		**TGVI**	$ Per MJ	$0.0118	8									
33		**Electricity**	$ Per MJ	$0.0155										
34		**Electricity**	$ per kWh	$0.0558	190		189,764	Total Light Industrial and Commercial Customers in BC						
35		**Electricity**	$ per kW per year	$52	15									
36														
37	**TAX**													
38			**Year**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
39	1		*Year*		*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
40	2	Carbon	$ Per tonne		$10.00	$15.00	$20.00	$25.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
41	3	Carbon	$ Per GJ		$0.4988	$0.7482	$0.9976	$1.2470	$1.4964	$1.4964	$1.4964	$1.4964	$1.4964	$1.4964
42	4	GDP Deflator			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
43	5	Carbon (Real)			$0.50	$0.75	$1.00	$1.25	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
44	6	Net Present Value -2008				$1.12	$1.94	$2.90	$3.98	$5.00	$5.94	$6.83	$7.66	$8.44
45	7	Net Present Value -2009					$1.58	$2.60	$3.75	$4.83	$5.84	$6.79	$7.68	$8.51
46	8	Net Present Value -2010						$2.03	$3.26	$4.41	$5.49	$6.50	$7.45	$8.34
47														
48		**Discount Rate (real)[1]**												
49		**TERASEN GAS**												
50		**Rate of Inflation**	1.90%											
51		**TGI**	6.75%											
52		**TGVI**	6.38%											
53		**BC HYDRO**												
54		**Rate of Inflation**	2.00%											
55		**BC Hydro**	6.00%											
56		**Customer**	6.00%											
57		*Footnote 1: Source LR 070531*												

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for EE EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	8.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	1.00			Net-to-Gross
Alternate Energy Impact	0.09	GJ		25	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	15	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			18,000	18,000	18,000	Information only
Participants	4,251	5,000	500	1,500	3,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	35,283	41,500	4,150	12,450	24,900	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	35,283	41,500	4,150	12,450	24,900	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	108,139	125,000	12,500	37,500	75,000	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$88.33	$87.51	$88.11	
Energy Purchases	$ 3,649,996	$ 3,649,996	$ 366,552	$ 1,089,551	$ 2,193,893	
Utility Program Costs						
DSM Incentives		$ 1,000,000	$ 100,000	$ 300,000	$ 600,000	
Administration		$ 243,999	$ 101,333	$ 41,333	$ 101,333	
Subtotal	$ 1,064,709	$ 1,243,999	$ 201,333	$ 341,333	$ 701,333	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 157,824	$ 15,782	$ 47,347	$ 94,694	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 157,824	$ 157,824	$ 15,782	$ 47,347	$ 94,694	
Net Benefit (Cost)	$ 2,743,110		$ 181,001	$ 795,565	$ 1,587,255	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.6**		**1.90**	**3.33**	**3.26**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.3**		**$ 5.2**	**$ 3.0**	**$ 3.0**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for EE E* Clothes Washers

PER MEASURE

Total Cost	$	100
Incentive	$	50
Participant	$	50

Annual Impact Per Measure

Energy Savings per installation	3.4	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0	1.00			Net-to-Gross
Alternate Energy Impact	1.0768	GJ	299		kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	14	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			8600	8600	8600	Information only
Participants	2,579	3,000	500	1,000	1,500	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	8,769	10,200	1,700	3,400	5,100	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	8,769	10,200	1,700	3,400	5,100	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	784,007	897,333	149,556	299,111	448,667	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$83.86	$84.40	
Energy Purchases	$ 859,527	$ 859,527	$ 143,990	$ 285,118	$ 430,419	
Utility Program Costs						
DSM Incentives		$ 150,000	$ 25,000	$ 50,000	$ 75,000	
Administration		$ 207,999	$ 94,333	$ 39,333	$ 74,333	
Subtotal	$ 312,951	$ 357,999	$ 119,333	$ 89,333	$ 149,333	
Participants' Net Costs						
Incremental Cost		$ 150,000	$ 25,000	$ 50,000	$ 75,000	
Subtotal	$ 128,955	$ 150,000	$ 25,000	$ 50,000	$ 75,000	
Alternate Savings - Net						
Energy (Purchases)		$ 1,084,291	$ 180,715	$ 361,430	$ 542,145	$1.208 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 1,084,291	$ 1,084,291	$ 180,715	$ 361,430	$ 542,145	
Net Benefit (Cost)	$ 1,501,912		$180,372	$507,215	$748,231	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.40**		**2.25**	**4.64**	**4.34**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.7**		**$ 9.6**	**$ 4.6**	**$ 5.0**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for EE E* Dishwashers

PER MEASURE

Total Cost	$	50
Incentive	$	25
Participant	$	25

Annual Impact Per Measure

Energy Savings per installation	2.5	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0	1.00			Net-to-Gross
Alternate Energy Impact	0.1	GJ		28	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	13	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			15,500	15,500	15,500	Information only
Participants	7,795	9,000	2,000	3,000	4,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	19,487	22,500	5,000	7,500	10,000	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	19,487	22,500	5,000	7,500	10,000	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	219,868	250,000	55,556	83,333	111,111	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$80.68	$79.99	$80.49	
Energy Purchases	$ 1,808,241	$ 1,808,241	$ 403,399	$ 599,909	$ 804,932	
Utility Program Costs						
DSM Incentives		$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Administration		$ 205,000	$ 40,000	$ 60,000	$ 105,000	
Subtotal	$ 371,311	$ 430,000	$ 90,000	$ 135,000	$ 205,000	
Participants' Net Costs						
Incremental Cost		$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Subtotal	$ 194,866	$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Alternate Savings - Net						
Energy (Purchases)		$ 287,712	$ 63,936	$ 95,904	$ 127,872	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 287,712	$ 287,712	$ 63,936	$ 95,904	$ 127,872	
Net Benefit (Cost)	$ 1,529,776		$327,335	$485,813	$627,804	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.70**		**3.34**	**3.31**	**3.06**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.4**		**$ 3.3**	**$ 3.3**	**$ 3.6**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for FS Gas Cooking Range

PER MEASURE

Total Cost	$	-
Incentive	$	50
Participant	$	(50)

Annual Impact Per Measure

Energy Savings per installation	-9.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0	1.00			Net-to-Gross
Alternate Energy Impact	3.7	GJ		1,028	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			10,500	10,500	10,500	Information only
Participants	10,431	12,000	3,000	4,000	5,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-97,009	-111,600	-27,900	-37,200	-46,500	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-97,009	-111,600	-27,900	-37,200	-46,500	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	10,882,390	12,333,334	3,083,334	4,111,111	5,138,889	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$98.21	$97.57	$98.46	
Energy Purchases	$(10,947,921)	$ (10,947,921)	$ (2,739,954)	$ (3,629,747)	$ (4,578,220)	
Utility Program Costs						
DSM Incentives		$ 600,000	$ 150,000	$ 200,000	$ 250,000	
Administration		$ 413,999	$ 146,333	$ 111,333	$ 156,333	
Subtotal	$ 884,860	$ 1,013,999	$ 296,333	$ 311,333	$ 406,333	
Participants' Net Costs						
Incremental Cost		$ (600,000)	$ (150,000)	$ (200,000)	$ (250,000)	
Subtotal	$ (521,555)	$ (600,000)	$ (150,000)	$ (200,000)	$ (250,000)	
Alternate Savings - Net						
Energy (Purchases)		$ 17,360,259	$ 4,340,065	$ 5,786,753	$ 7,233,441	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 17,360,259	$ 17,360,259	$ 4,340,065	$ 5,786,753	$ 7,233,441	
Net Benefit (Cost)	$ 6,049,033		$1,453,778	$2,045,673	$2,498,888	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**17.65**		**10.93**	**19.37**	**16.98**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
NEW

Measure Data for FS Gas Clothes Dryer

PER MEASURE

Total Cost	$ -				
Incentive	$ 50				
Participant	$ (50)				
Annual Impact Per Measure					
Energy Savings per installation	-4.3	GJ		Average Annnual Energy Savings per Measure	
Free Rider Rate / Net-to-Gross	0	1.00		Net-to-Gross	
Alternate Energy Impact	3.2	GJ	889	kWh	
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			6,600	6,600	6,600	Information only
Participants	3,634	4,200	900	1,400	1,900	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-15,625	-18,060	-3,870	-6,020	-8,170	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-15,625	-18,060	-3,870	-6,020	-8,170	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	3,280,292	3,733,334	800,000	1,244,445	1,688,889	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$98.21	$97.57	$98.46	
Energy Purchases	$ (1,771,841)	$ (1,771,841)	$ (380,058)	$ (587,394)	$ (804,388)	
Utility Program Costs						
DSM Incentives		$ 210,000	$ 45,000	$ 70,000	$ 95,000	
Administration		$ 109,000	$ 18,000	$ 28,000	$ 63,000	
Subtotal	$ 274,910	$ 319,000	$ 63,000	$ 98,000	$ 158,000	
Participants' Net Costs						
Incremental Cost		$ (210,000)	$ (45,000)	$ (70,000)	$ (95,000)	
Subtotal	$ (181,684)	$ (210,000)	$ (45,000)	$ (70,000)	$ (95,000)	
Alternate Savings - Net						
Energy (Purchases)		$ 5,254,997	$ 1,126,071	$ 1,751,666	$ 2,377,261	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 5,254,997	$ 5,254,997	$ 1,126,071	$ 1,751,666	$ 2,377,261	
Net Benefit (Cost)	$ 3,389,930		$728,013	$1,136,271	$1,509,872	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**37.36**		**41.45**	**41.58**	**24.97**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
RETROFIT

Measure Data for EE E* Furnace Upgrade

PER MEASURE

Total Cost	$	600
Incentive	$	300
Participant	$	300

Annual Impact Per Measure

Energy Savings per installation	13.8	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0	1.00			Net-to-Gross
Alternate Energy Impact	0.0	GJ		0	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			18,500	18,500	18,500	Information only
Participants	7,257	8,000	4,000	4,000	0	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	100,152	110,400	55,200	55,200	0	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	100,152	110,400	55,200	55,200	0	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	0	0	0	0	0	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$98.21	$97.57	$98.46	
Energy Purchases	$ 10,807,060	$ 10,807,060	$ 5,420,985	$ 5,386,076	$ -	
Utility Program Costs						
DSM Incentives		$ 2,400,000	$ 1,200,000	$ 1,200,000	$ -	
Administration		$ 753,332	$ 376,666	$ 376,666	$ -	
Subtotal	$ 2,860,629	$ 3,153,332	$ 1,576,666	$ 1,576,666	$ -	
Participants' Net Costs						
Incremental Cost		$ 2,400,000	$ 1,200,000	$ 1,200,000	$ -	
Subtotal	$ 2,177,224	$ 2,400,000	$ 1,200,000	$ 1,200,000	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Benefit (Cost)	$ 5,769,208		$2,644,319	$2,609,410	$0	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.15**		**1.95**	**1.94**	**-**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.9**		**$ 4.9**	**$ 4.9**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
RETROFIT

Measure Data for EE EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	8.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0	1.00			Net-to-Gross
Alternate Energy Impact	0.09	GJ		25	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	15	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			6,000	6,000	6,000	Information only
Participants	6,534	7,500	2,000	2,500	3,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	54,230	62,250	16,600	20,750	24,900	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	54,230	62,250	16,600	20,750	24,900	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	165,766	187,500	50,000	62,500	75,000	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$88.33	$87.51	$88.11	
Energy Purchases	$ 5,476,018	$ 5,476,018	$ 1,466,207	$ 1,815,918	$ 2,193,893	
Utility Program Costs						
DSM Incentives		$ 1,500,000	$ 400,000	$ 500,000	$ 600,000	
Administration		$ 670,999	$ 224,333	$ 203,333	$ 243,333	
Subtotal	$ 1,895,386	$ 2,170,999	$ 624,333	$ 703,333	$ 843,333	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 236,736	$ 63,130	$ 78,912	$ 94,694	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 236,736	$ 236,736	$ 63,130	$ 78,912	$ 94,694	
Net Benefit (Cost)	$ 3,817,368		$905,004	$1,191,497	$1,445,255	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.01**		**2.45**	**2.69**	**2.71**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.8**		**$ 4.1**	**$ 3.7**	**$ 3.7**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
RETROFIT

Measure Data for E* Dishwasher

PER MEASURE

Total Cost	$	50
Incentive	$	25
Participant	$	25

Annual Impact Per Measure

Energy Savings per installation	2.5	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0	1.00		Net-to-Gross
Alternate Energy Impact	0.1	GJ	28	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	13	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			44,000	44,000	44,000	Information only
Participants	7,795	9,000	2,000	3,000	4,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	19,487	22,500	5,000	7,500	10,000	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	19,487	22,500	5,000	7,500	10,000	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	219,868	250,000	55,556	83,333	111,111	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$80.68	$79.99	$80.49	
Energy Purchases	$ 1,808,241	$ 1,808,241	$ 403,399	$ 599,909	$ 804,932	
Utility Program Costs						
DSM Incentives		$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Administration		$ 340,999	$ 104,333	$ 93,333	$ 143,333	
Subtotal	$ 492,343	$ 565,999	$ 154,333	$ 168,333	$ 243,333	
Participants' Net Costs						
Incremental Cost		$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Subtotal	$ 194,866	$ 225,000	$ 50,000	$ 75,000	$ 100,000	
Alternate Savings - Net						
Energy (Purchases)		$ 287,712	$ 63,936	$ 95,904	$ 127,872	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 287,712	$ 287,712	$ 63,936	$ 95,904	$ 127,872	
Net Benefit (Cost)	$ 1,408,744		$263,002	$452,480	$589,471	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.05**		**2.29**	**2.86**	**2.72**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.2**		**$ 4.8**	**$ 3.8**	**$ 4.0**	Informational (for comparison with supply options)

TERASEN GAS INC
RESIDENTIAL
RETROFIT

Measure Data for E* Clothes Washer

PER MEASURE

Total Cost	$	100
Incentive	$	50
Participant	$	50

Annual Impact Per Measure

Energy Savings per installation	3.4	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0	1.00		Net-to-Gross
Alternate Energy Impact	1.0968	GJ	305	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	14	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			40,000	40,000	40,000	Information only
Participants	7,795	9,000	2,000	3,000	4,000	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	26,502	30,600	6,800	10,200	13,600	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	26,502	30,600	6,800	10,200	13,600	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	2,411,516	2,742,000	609,333	914,000	1,218,667	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	$0.00	-				Other Utility Billed capacity impact

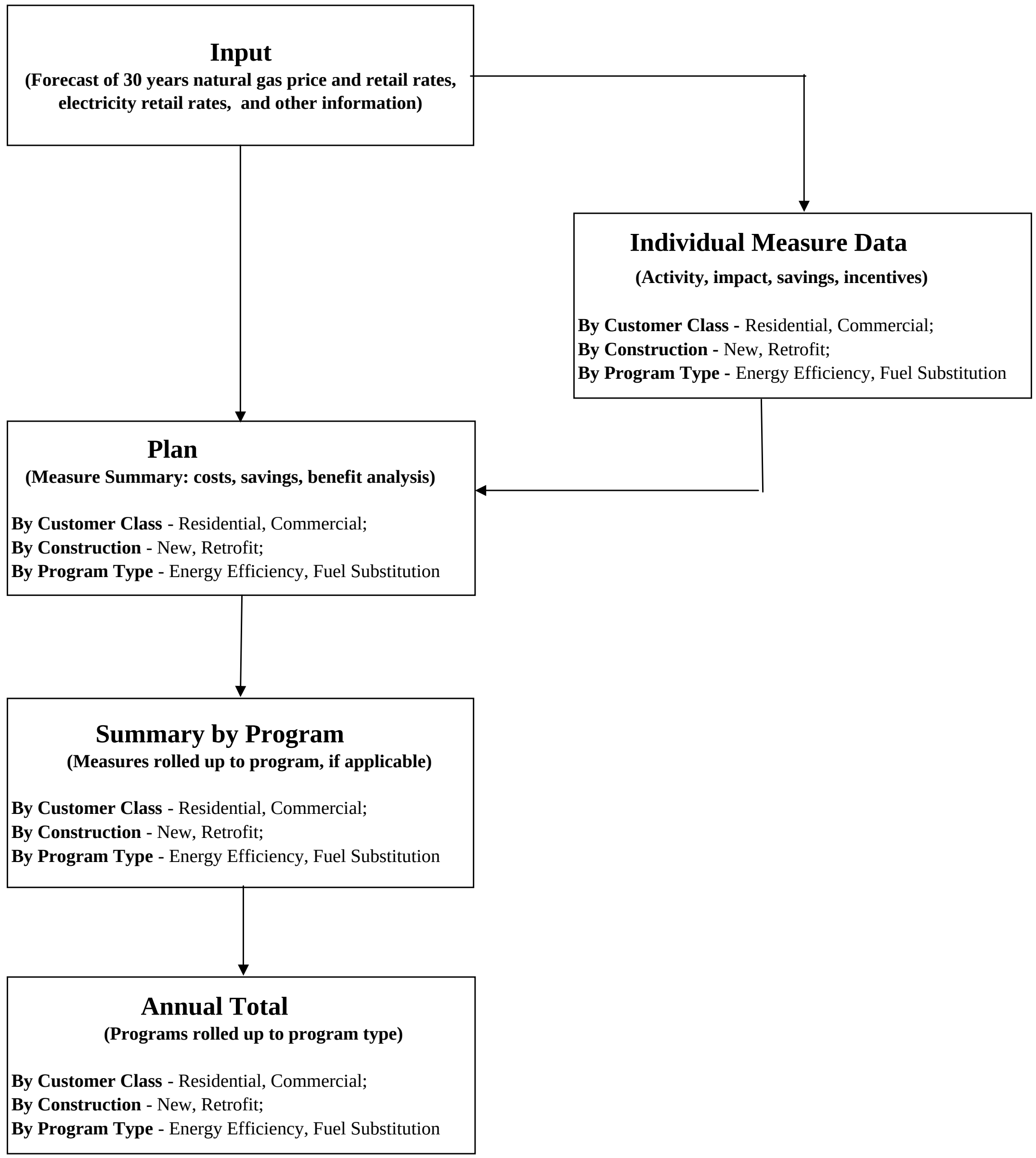
Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$84.70	$83.86	$84.40	
Energy Purchases	$ 2,579,098	$ 2,579,098	$ 575,961	$ 855,353	$ 1,147,784	
Utility Program Costs						
DSM Incentives		$ 450,000	$ 100,000	$ 150,000	$ 200,000	
Administration		$ 180,000	$ 40,000	$ 60,000	$ 80,000	
Subtotal	$ 545,625	$ 630,000	$ 140,000	$ 210,000	$ 280,000	
Participants' Net Costs						
Incremental Cost		$ 450,000	$ 100,000	$ 150,000	$ 200,000	
Subtotal	$ 389,732	$ 450,000	$ 100,000	$ 150,000	$ 200,000	
Alternate Savings - Net						
Energy (Purchases)		$ 3,313,290	$ 736,287	$ 1,104,430	$ 1,472,573	$1.208 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 3,313,290	$ 3,313,290	$ 736,287	$ 1,104,430	$ 1,472,573	
Net Benefit (Cost)	$ 4,957,031		$1,072,248	$1,599,783	$2,140,357	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**6.30**		**5.47**	**5.44**	**5.46**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.0**		**$ 4.0**	**$ 4.0**	**$ 4.0**	Informational (for comparison with supply options)

Table of Contents

Sheet Name	Description	MEASURE_NAME
Annual Total	Program Type Summary - costs, savings, and benefit analysis	
Summary by Program	Program Summary - costs, savings, and benefit analysis - annual and total	
Plan	Measures Summary - costs, savings, and benefit analysis - annual	
Input	30 years Natural Gas Price, and other inputs to the model	
EEbldg 30% Large	Measure data and benefit analysis for Efficient Design - 30% Large (New Construction)	EE Building Design (30% Large)
EEbldg 30% Small	Measure data and benefit analysis for Efficient Design - 30% Small (New Construction)	EE Building Design (30% Small)
EEbldg 60%	Measure data and benefit analysis for Efficient Design - 60% (New Construction)	EE Building Design (60%)
HP Glazing Hit	Measure data and benefit analysis for HIT Windows (New Construction)	High Performance Glazing HIT
NearCond Boilers	Measure data and benefit analysis for Near Condensing Boilers (New Construction)	Near Condensing Boiler
Cond Boilers	Measure data and benefit analysis for Condensing Boilers (New Construction)	Condensing Boiler
Inst DHW Heaters	Measure data and benefit analysis for Instantaneous DHW Heaters (New Construction)	Instantaneous DHW Heater
Cond DHW Boilers	Measure data and benefit analysis for Condensing DHW Boilers (New Construction)	Condensing DHW Boiler
Cond DHW Heaters	Measure data and benefit analysis for Condensing DHW Heaters (New Construction)	Condensing DHW Heater
Drainwater Heat Rec	Measure data and benefit analysis for Drainwater Heat Recovery (New Construction)	Drainwater Heat Recovery
Retrofit NearCondBoilers	Measure data and benefit analysis for Near Condensing Boilers (Retrofit)	Near Condensing Boiler
Retrofit CondBoilers	Measure data and benefit analysis for Condensing Boilers (Retrofit)	Condensing Boiler
Retrofit Bldg Re-Comm	Measure data and benefit analysis for Building Recommissioning (Retrofit)	Building Recommissioning
Retrofit NextGenBAS	Measure data and benefit analysis for Next Generation BAS (Retrofit)	Next Generation Building Automation System
Retrofit HE Roof Top	Measure data and benefit analysis for HE Rooftop units (Retrofit)	High Efficiency Roof Top Unit
Retrofit Inst DHW Heaters	Measure data and benefit analysis for Instantaneous DHW Heaters (Retrofit)	Instantaneous DHW Heaters
Retrofit Cond DHW Boilers	Measure data and benefit analysis for Condensing DHW Boilers (Retrofit)	Condensing DHW Boiler
Retrofit Cond DHW Heaters	Measure data and benefit analysis for Condensing DHW Heaters (Retrofit)	Condensing DHW Heater

PROGRAM NAME
Efficient New Construction
Efficient New Construction
Efficient New Construction
Efficient New Construction
Boilers
Boilers
Water Heating
Water Heating
Water Heating
Water Heating
Boilers
Boilers
Building Recommissioning
Next Generation Building Automation System
High Efficiency Roof Top Unit
Water Heating
Water Heating
Water Heating


Input
(Forecast of 30 years natural gas price and retail rates, electricity retail rates, and other information)
Individual Measure Data
(Activity, impact, savings, incentives)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Plan
(Measure Summary: costs, savings, benefit analysis)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Summary by Program
(Measures rolled up to program, if applicable)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Annual Total
(Programs rolled up to program type)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution

TERASEN GAS VANCOUVER ISLAND

		PROGRAM									ALTERNATE	
		COSTS ($000)							SAVINGS (GJ)		Impact	
		Utility									Energy	Capacity
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW
2008												
COMMERCIAL:												
New Construction	7	73	16	89	73	163	55%	45%	3,689	3,689	-	-
Retrofit	17	308	95	403	308	711	57%	43%	14,121	14,121	900	-
2008 Total Commercial	**24**	**381**	**111**	**492**	**381**	**873**	**56%**	**44%**	**17,810**	**17,810**	**900**	**-**
2009												
COMMERCIAL:												
New Construction	8	74	15	90	74	164	55%	45%	3,763	3,763	-	-
Retrofit	27	474	121	595	474	1,069	56%	44%	20,371	20,371	1,125	-
2009 Total Commercial	**35**	**548**	**136**	**684**	**548**	**1,233**	**56%**	**44%**	**24,133**	**24,133**	**1,125**	**-**
2010												
COMMERCIAL:												
New Construction	17	798	78	876	886	1,761	50%	50%	11,767	11,767	3,044	-
Retrofit	37	625	171	796	625	1,421	56%	44%	27,667	27,667	2,025	-
2010 Total Commercial	**54**	**1,422**	**249**	**1,671**	**1,511**	**3,182**	**53%**	**47%**	**39,434**	**39,434**	**5,069**	**-**
2008 - 2010 (NPV 2007)												
COMMERCIAL:												
New Construction	28	797	94	891	870	1,761	51%	49%	16,567	16,567	2,528	-
Retrofit	71	1,227	338	1,565	1,227	2,792	56%	44%	54,256	54,256	3,522	-
2008 - 2010 Total Commercial	**98**	**2,024**	**431**	**2,456**	**2,098**	**4,553**	**54%**	**46%**	**70,823**	**70,823**	**6,051**	**-**

	NET PRESENT VALUE									BENEFIT/COST						
	Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings				Participant					
	($/GJ)	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	Natural Gas Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2008																
COMMERCIAL:																
New Construction	2	420	-	537	59	-	44,001	-	-	4.7	73	596	8.1	0.7	2.6	257
Retrofit	2	1,551	861	1,986	218	370	162,701	6,624	-	3.9	308	2,573	8.4	0.6	3.4	1,701
2008 Total Commercial	**2**	**1,971**	**861**	**2,524**	**276**	**370**	**206,702**	**6,624**	**-**	**4.0**	**381**	**3,170**	**8.3**	**0.7**	**3.2**	**1,959**
2009																
COMMERCIAL:																
New Construction	2	425	-	546	63	-	44,694	-	-	4.7	74	609	8.2	0.7	2.6	261
Retrofit	3	2,237	1,076	2,877	333	462	235,637	8,280	-	3.8	474	3,671	7.7	0.6	3.1	2,245
2009 Total Commercial	**2**	**2,662**	**1,076**	**3,423**	**396**	**462**	**280,331**	**8,280**	**-**	**3.9**	**548**	**4,280**	**7.8**	**0.6**	**3.0**	**2,506**
2010																
COMMERCIAL:																
New Construction	6	1,367	5,059	1,737	208	2,171	142,131	38,912	-	1.6	886	4,117	4.6	0.5	3.6	4,664
Retrofit	3	2,999	1,938	3,833	462	832	314,155	14,904	-	3.8	625	5,127	8.2	0.6	3.5	3,516
2010 Total Commercial	**4**	**4,366**	**6,996**	**5,570**	**670**	**3,003**	**456,286**	**53,816**	**-**	**2.6**	**1,511**	**9,243**	**6.1**	**0.6**	**3.6**	**8,180**
2008 - 2010 (NPV 2007)																
COMMERCIAL:																
New Construction	4	2,212	5,059	2,820	330	2,171	230,826	38,912	-	2.5	870	5,322	6.1	0.6	4.1	5,510
Retrofit	2	6,787	3,875	8,696	1,012	1,663	712,493	29,808	-	4.3	1,227	11,372	9.3	0.7	3.8	7,870
2008 - 2010 Total Commercial	**3**	**8,999**	**8,934**	**11,516**	**1,342**	**3,835**	**943,319**	**68,720**	**-**	**3.7**	**2,098**	**16,693**	**8.0**	**0.6**	**3.9**	**13,379**

TERASEN GAS VANCOUVER ISLAND

		PROGRAM									ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings			Natural Gas	Participant			Natural Gas		TRC Net Benefits
		Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity							
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Rate Impact	Total Resource	($'000s)
2008																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Boilers	2	53	11	64	53	117	55%	45%	1,754	1,754	-	-	3	208	-	265	29	-	21,635	-	-	3.2	53	294	5.6	0.6	1.8	91
Water Heating	5	20	5	25	20	46	56%	44%	1,935	1,935	-	-	1	212	-	273	30	-	22,366	-	-	8.4	20	303	14.9	0.7	4.6	167
Subtotal New Constuction	**7**	**73**	**16**	**89**	**73**	**163**	**55%**	**45%**	**3,689**	**3,689**	-	-	2	**420**	-	**537**	**59**	-	**44,001**	-	-	**4.7**	**73**	**596**	**8.1**	**0.7**	**2.6**	**257**
Retrofit																												
Boilers	9	223	33	256	223	478	53%	47%	9,333	9,333	-	-	2	1,105	-	1,408	154	-	115,118	-	-	4.3	223	1,562	7.0	0.7	2.3	626
Building Recommissioning	2	64	26	90	64	154	58%	42%	1,950	1,950	900	-	6	126	861	169	18	370	14,097	6,624	-	1.4	64	557	8.7	0.5	6.4	833
Next Generation Building Automa	-	-	1	1	-	1	100%	0%	-	-	-	-	LB	-	-	-	-	-	-	-	-	LB	-	-	N/A	N/A	LB	LB
High Efficiency Roof Top Unit	-	-	1	1	-	1	100%	0%	-	-	-	-	LB	-	-	-	-	-	-	-	-	LB	-	-	N/A	N/A	LB	LB
Water Heating	6	21	34	55	21	76	72%	28%	2,838	2,838	-	-	2	320	-	409	45	-	33,486	-	-	5.8	21	454	21.5	0.7	4.2	244
Subtotal Retrofit	**17**	**308**	**95**	**403**	**308**	**711**	**57%**	**43%**	**14,121**	**14,121**	**900**	-	2	**1,551**	**861**	**1,986**	**218**	**370**	**162,701**	**6,624**	-	**3.9**	**308**	**2,573**	**8.4**	**0.6**	**3.4**	**1,701**
2008 Total Commercial	**24**	**381**	**111**	**492**	**381**	**873**	**56%**	**44%**	**17,810**	**17,810**	**900**	-	2	**1,971**	**861**	**2,524**	**276**	**370**	**206,702**	**6,624**	-	**4.0**	**381**	**3,170**	**8.3**	**0.7**	**3.2**	**1,959**
2009																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Boilers	2	53	9	62	53	115	54%	46%	1,754	1,754	-	-	3	207	-	265	31	-	21,635	-	-	3.3	53	295	5.6	0.6	1.8	92
Water Heating	6	21	6	27	21	49	56%	44%	2,009	2,009	-	-	1	218	-	281	33	-	23,059	-	-	7.9	21	314	14.7	0.7	4.5	169
Subtotal New Constuction	**8**	**74**	**15**	**90**	**74**	**164**	**55%**	**45%**	**3,763**	**3,763**	-	-	2	**425**	-	**546**	**63**	-	**44,694**	-	-	**4.7**	**74**	**609**	**8.2**	**0.7**	**2.6**	**261**
Retrofit																												
Boilers	12	332	41	373	332	705	53%	47%	13,374	13,374	-	-	2	1,579	-	2,017	233	-	164,962	-	-	4.2	332	2,250	6.8	0.7	2.2	874
Building Recommissioning	2	64	26	90	64	154	58%	42%	1,950	1,950	900	-	6	124	861	169	20	370	14,097	6,624	-	1.4	64	559	8.7	0.5	6.4	831
Next Generation Building Automa	1	40	7	47	40	87	54%	46%	487	487	225	-	13	31	215	42	5	92	3,521	1,656	-	0.7	40	140	3.5	0.3	2.8	159
High Efficiency Roof Top Unit	1	5	3	8	5	12	63%	37%	122	122	-	-	6	13	-	16	2	-	1,355	-	-	1.7	5	18	4.1	0.5	1.1	1
Water Heating	11	34	43	77	34	111	70%	30%	4,438	4,438	-	-	1	491	-	631	73	-	51,702	-	-	6.4	34	704	20.9	0.7	4.4	380
Subtotal Retrofit	**27**	**474**	**121**	**595**	**474**	**1,069**	**56%**	**44%**	**20,371**	**20,371**	**1,125**	-	3	**2,237**	**1,076**	**2,877**	**333**	**462**	**235,637**	**8,280**	-	**3.8**	**474**	**3,671**	**7.7**	**0.6**	**3.1**	**2,245**
2009 Total Commercial	**35**	**548**	**136**	**684**	**548**	**1,233**	**56%**	**44%**	**24,133**	**24,133**	**1,125**	-	2	**2,662**	**1,076**	**3,423**	**396**	**462**	**280,331**	**8,280**	-	**3.9**	**548**	**4,280**	**7.8**	**0.6**	**3.0**	**2,506**
2010																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	4	669	57	727	758	1,484	49%	51%	5,029	5,029	3,044	-	12	599	5,059	759	91	2,171	62,024	38,912	-	0.8	758	3,021	4.0	0.4	3.8	4,173
Boilers	3	88	10	98	88	185	53%	47%	2,868	2,868	-	-	3	342	-	433	52	-	35,375	-	-	3.5	88	484	5.5	0.6	1.8	156
Water Heating	10	41	10	51	41	91	56%	44%	3,871	3,871	-	-	1	427	-	546	66	-	44,732	-	-	8.4	41	611	15.0	0.7	4.7	335
Subtotal New Constuction	**17**	**798**	**78**	**876**	**886**	**1,761**	**50%**	**50%**	**11,767**	**11,767**	**3,044**	-	6	**1,367**	**5,059**	**1,737**	**208**	**2,171**	**142,131**	**38,912**	-	**1.6**	**886**	**4,117**	**4.6**	**0.5**	**3.6**	**4,664**
Retrofit																												
Boilers	14	398	47	445	398	842	53%	47%	15,882	15,882	-	-	2	1,891	-	2,396	287	-	195,896	-	-	4.3	398	2,683	6.7	0.7	2.2	1,049
Building Recommissioning	4	128	46	174	128	302	58%	42%	3,900	3,900	1,800	-	6	248	1,722	339	42	739	28,195	13,248	-	1.4	128	1,120	8.8	0.5	6.5	1,668
Next Generation Building Automa	1	40	7	47	40	87	54%	46%	487	487	225	-	13	31	215	42	5	92	3,521	1,656	-	0.7	40	140	3.5	0.3	2.8	159
High Efficiency Roof Top Unit	1	5	3	8	5	12	63%	37%	122	122	-	-	6	13	-	16	2	-	1,355	-	-	1.7	5	18	4.1	0.5	1.1	1
Water Heating	17	55	67	122	55	177	69%	31%	7,276	7,276	-	-	1	816	-	1,040	125	-	85,188	-	-	6.7	55	1,165	21.3	0.7	4.6	639
Subtotal Retrofit	**37**	**625**	**171**	**796**	**625**	**1,421**	**56%**	**44%**	**27,667**	**27,667**	**2,025**	-	3	**2,999**	**1,938**	**3,833**	**462**	**832**	**314,155**	**14,904**	-	**3.8**	**625**	**5,127**	**8.2**	**0.6**	**3.5**	**3,516**
2010 Total Commercial	**54**	**1,422**	**249**	**1,671**	**1,511**	**3,182**	**53%**	**47%**	**39,434**	**39,434**	**5,069**	-	4	**4,366**	**6,996**	**5,570**	**670**	**3,003**	**456,286**	**53,816**	-	**2.6**	**1,511**	**9,243**	**6.1**	**0.6**	**3.6**	**8,180**
2008 - 2010 (NPV 2007)																												
COMMERCIAL:																												
New Construction																												
Efficient New Construction	3	556	48	604	629	1,233	49%	51%	4,177	4,177	2,528	-	10	599	5,059	759	91	2,171	62,024	38,912	-	1.0	629	3,021	4.8	0.4	4.6	4,424
Boilers	6	169	27	197	169	366	54%	46%	5,581	5,581	-	-	2	756	-	962	111	-	78,645	-	-	3.8	169	1,073	6.3	0.7	2.1	390
Water Heating	18	72	18	90	72	162	56%	44%	6,809	6,809	-	-	1	857	-	1,100	128	-	90,157	-	-	9.5	72	1,228	17.1	0.7	5.3	695
Subtotal New Constuction	**28**	**797**	**94**	**891**	**870**	**1,761**	**51%**	**49%**	**16,567**	**16,567**	**2,528**	-	4	**2,212**	**5,059**	**2,820**	**330**	**2,171**	**230,826**	**38,912**	-	**2.5**	**870**	**5,322**	**6.1**	**0.6**	**4.1**	**5,510**
Retrofit																												
Boilers	31	833	106	939	833	1,772	53%	47%	33,784	33,784	-	-	2	4,575	-	5,821	674	-	475,976	-	-	4.9	833	6,495	7.8	0.7	2.6	2,802
Building Recommissioning	7	223	86	309	223	532	58%	42%	6,796	6,796	3,136	-	5	498	3,445	677	81	1,478	56,389	26,496	-	1.6	223	2,237	10.0	0.5	7.4	3,411
Next Generation Building Automa	2	69	13	82	69	150	54%	46%	835	835	386	-	12	62	431	85	10	185	7,041	3,312	-	0.8	69	280	4.1	0.4	3.3	342
High Efficiency Roof Top Unit	2	8	6	14	8	22	64%	36%	209	209	-	-	5	25	-	33	4	-	2,710	-	-	1.8	8	37	4.8	0.5	1.2	4
Water Heating	29	95	126	221	95	316	70%	30%	12,633	12,633	-	-	1	1,627	-	2,080	243	-	170,376	-	-	7.4	95	2,323	24.4	0.7	5.1	1,311
Subtotal Retrofit	**71**	**1,227**	**338**	**1,565**	**1,227**	**2,792**	**56%**	**44%**	**54,256**	**54,256**	**3,522**	-	2	**6,787**	**3,875**	**8,696**	**1,012**	**1,663**	**712,493**	**29,808**	-	**4.3**	**1,227**	**11,372**	**9.3**	**0.7**	**3.8**	**7,870**
2008 - 2010 Total Commercial	**98**	**2,024**	**431**	**2,456**	**2,098**	**4,553**	**54%**	**46%**	**70,823**	**70,823**	**6,051**	-	**3**	**8,999**	**8,934**	**11,516**	**1,342**	**3,835**	**943,319**	**68,720**	-	**3.7**	**2,098**	**16,693**	**8.0**	**0.6**	**3.9**	**13,379**

TERASEN GAS VANCOUVER ISLAND

		PROGRAM											ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)			LIFE	Impact		Levelized Cost	Utility Benefits		Participant Benefits (Costs)			Program Net Savings				Participant					
		Utility										Years	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas				Natural Gas		TRC Net Benefits
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net-to-Gross	Net		MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Rate Impact	Total Resource	($'000s)
Label	Label	B	C	D	E	F	G	H	Input (program)	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
Source Sheet or Calculation	Source Sheet or Calculation	Program	Program	B+C	Program	D+E	D/F	E/F	Program	Program	IxJ	Program	Program	Program	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2008																														
COMMERCIAL:																														
New Construction																														
EE Building Design (30% Large)	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE Building Design (30% Small)	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE Building Design (60%)	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
High Performance Glazing HIT	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Near Condensing Boiler	1	18	9	27	18	46	60%	40%	640	100%	640	25	-	-	6	76	N/A	97	10.6	N/A	7,894	-	-	2.8	18	107	5.9	0.6	1.7	30
Condensing Boiler	1	35	2	37	35	71	51%	49%	1,114	100%	1,114	25	-	-	5	132	N/A	168	18.4	N/A	13,741	-	-	3.6	35	186	5.4	0.6	1.8	61
Instantaneous DHW Heater	2	2	2	4	2	6	63%	37%	146	100%	146	15	-	-	4	13	N/A	17	1.8	N/A	1,387	-	-	3.5	2	19	8.9	0.6	2.2	7
Condensing DHW Boiler	1	9	1	10	9	18	53%	47%	1,238	100%	1,238	25	-	-	1	147	N/A	187	20.5	N/A	15,270	-	-	15.4	9	207	24.4	0.7	8.1	129
Condensing DHW Heater	1	1	1	2	1	3	67%	33%	108	100%	108	10	-	-	4	7	N/A	9	1.0	N/A	779	-	-	3.5	1	10	10.4	0.6	2.3	4
Drainwater Heat Recovery	1	9	2	10	9	19	54%	46%	443	100%	443	20	-	-	4	46	N/A	60	6.6	N/A	4,929	-	-	4.5	9	67	7.6	0.7	2.4	27
Retrofit																														
Near Condensing Boiler	8	180	29	208	180	388	54%	46%	7,800	100%	7,800	25	-	-	4	923	N/A	1,177	129.1	N/A	96,209	-	-	4.4	180	1,306	7.3	0.7	2.4	536
Condensing Boiler	1	43	4	47	43	91	52%	48%	1,533	100%	1,533	25	-	-	5	181	N/A	231	25.4	N/A	18,909	-	-	3.8	43	257	5.9	0.7	2.0	91
Building Recommissioning	2	64	26	90	64	154	58%	42%	1,950	100%	1,950	10	900	-	11	126	861	169	18.3	370	14,097	6,624	-	1.4	64	557	8.7	0.5	6.4	833
Next Generation Building Automation System	-	-	1	1	-	1	100%	-	0	100%	0	10	-	-	LB	LB	N/A	LB	-	N/A	-	-	-	LB	-	-	N/A	N/A	LB	LB
High Efficiency Roof Top Unit	-	-	1	1	-	1	100%	-	0	100%	0	20	-	-	LB	LB	N/A	LB	-	N/A	-	-	-	LB	-	-	N/A	N/A	LB	LB
Instantaneous DHW Heaters	2	2	22	24	2	26	92%	8%	146	100%	146	15	-	-	19	13	N/A	17	1.8	N/A	1,387	-	-	0.5	2	19	8.9	0.3	0.5	(14)
Condensing DHW Boiler	2	17	6	23	17	40	58%	43%	2,476	100%	2,476	25	-	-	1	293	N/A	373	41.0	N/A	30,540	-	-	12.7	17	414	24.4	0.7	7.3	253
Condensing DHW Heater	2	2	6	8	2	10	80%	20%	216	100%	216	10	-	-	6	14	N/A	19	2.0	N/A	1,559	-	-	1.7	2	21	10.4	0.5	1.4	4
2008 Total Commercial	24	381	111	492	381	873			17,810		17,810		900	-	4	1,971	861	2,524	276	370	206,702	6,624	-	4.0	381	3,170	8.3	0.7	3.2	1,959
2009																														
COMMERCIAL:																														
New Construction																														
EE Building Design (30% Large)	-	-	-	-	-	-	-	-	0	100%	0	25	-	-	-	-	-		-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE Building Design (30% Small)	-	-	-	-	-	-	-	-	0	100%	0	25	-	-	-	-	-		-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
EE Building Design (60%)	-	-	-	-	-	-	-	-	0	100%	0	25	-	-	-	-	-		-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
High Performance Glazing HIT	-	-	-	-	-	-	-	-	0	100%	0	25	-	-	-	-	-		-	-	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
Near Condensing Boiler	1	18	7	26	18	44	58%	42%	640	100%	640	25	-	-	6	76	N/A	97	11.1	N/A	7,894	-	-	3.0	18	108	5.9	0.6	1.7	32
Condensing Boiler	1	35	2	37	35	71	51%	49%	1,114	100%	1,114	25	-	-	5	131	N/A	168	19.4	N/A	13,741	-	-	3.6	35	187	5.4	0.6	1.8	60
Instantaneous DHW Heater	3	3	3	6	3	9	64%	36%	220	100%	220	15	-	-	4	19	N/A	25	2.9	N/A	2,081	-	-	3.3	3	28	8.9	0.6	2.1	10
Condensing DHW Boiler	1	9	1	10	9	18	53%	47%	1,238	100%	1,238	25	-	-	1	146	N/A	187	21.5	N/A	15,270	-	-	15.4	9	208	24.5	0.7	8.1	128
Condensing DHW Heater	1	1	1	2	1	3	67%	33%	108	100%	108	10	-	-	4	7	N/A	9	1.1	N/A	779	-	-	3.4	1	10	10.5	0.6	2.3	4
Drainwater Heat Recovery	1	9	2	10	9	19	54%	46%	443	100%	443	20	-	-	4	46	N/A	60	7.0	N/A	4,929	-	-	4.5	9	67	7.6	0.7	2.4	27
Retrofit																														
Near Condensing Boiler	9	202	29	231	202	433	53%	47%	8,775	100%	8,775	25	-	-	4	1,036	N/A	1,324	152.7	N/A	108,235	-	-	4.5	202	1,476	7.3	0.7	2.4	603
Condensing Boiler	3	130	12	142	130	272	52%	48%	4,599	100%	4,599	25	-	-	5	543	N/A	694	80.0	N/A	56,726	-	-	3.8	130	774	6.0	0.6	2.0	271
Building Recommissioning	2	64	26	90	64	154	58%	42%	1,950	100%	1,950	10	900	-	11	124	861	169	19.9	370	14,097	6,624	-	1.4	64	559	8.7	0.5	6.4	831
Next Generation Building Automation System	1	40	7	47	40	87	54%	46%	487	100%	487	10	225	-	25	31	215	42	5.0	92	3,521	1,656	-	0.7	40	140	3.5	0.3	2.8	159
High Efficiency Roof Top Unit	1	5	3	8	5	12	63%	37%	122	100%	122	20	-	-	9	13	N/A	16	1.9	N/A	1,355	-	-	1.7	5	18	4.1	0.5	1.1	1
Instantaneous DHW Heaters	4	4	22	26	4	31	86%	14%	293	100%	293	15	-	-	11	25	N/A	34	3.9	N/A	2,774	-	-	1.0	4	37	8.9	0.4	0.8	(5)
Condensing DHW Boiler	3	26	9	35	26	60	58%	43%	3,714	100%	3,714	25	-	-	1	438	N/A	560	64.6	N/A	45,810	-	-	12.7	26	625	24.5	0.7	7.3	378
Condensing DHW Heater	4	4	12	16	4	20	80%	20%	431	100%	431	10	-	-	6	27	N/A	37	4.4	N/A	3,117	-	-	1.7	4	42	10.5	0.5	1.4	7
2009 Total Commercial	35	548	136	684	548	1,233			24,133		24,133		1,125	-	4	2,662	1,076	3,423	396	462	280,331	8,280	-	3.9	548	4,280	7.8	0.6	3.0	2,506
2010																														
COMMERCIAL:																														
New Construction																														
EE Building Design (30% Large)	1	115	18	133	130	263	51%	49%	1,320	100%	1,320	25	542	-	16	157	901	199	23.8	387	16,280	6,928	-	1.2	130	610	4.7	0.5	4.0	795
EE Building Design (30% Small)	1	42	16	58	48	105	55%	45%	486	100%	486	25	189	-	18	58	315	73	8.8	135	5,995	2,420	-	1.0	48	217	4.6	0.4	3.5	267
EE Building Design (60%)	1	442	23	465	500	965	48%	52%	2,657	100%	2,657	25	2,169	-	29	316	3,604	401	48.0	1,547	32,774	27,721	-	0.7	500	1,996	4.0	0.4	4.1	2,955
High Performance Glazing HIT	1	71	-	71	80	151	47%	53%	566	100%	566	25	144	-	22	67	240	85	10.2	103	6,976	1,843	-	1.0	80	198	2.5	0.4	2.0	156
Near Condensing Boiler	1	18	7	26	18	44	58%	42%	640	100%	640	25	-	-	6	76	N/A	97	11.6	N/A	7,894	-	-	3.0	18	108	5.9	0.6	1.7	32
Condensing Boiler	2	69	3	72	69	142	51%	49%	2,228	100%	2,228	25	-	-	5	265	N/A	336	40.3	N/A	27,481	-	-	3.7	69	376	5.4	0.6	1.9	124
Instantaneous DHW Heater	4	4	3.5	8	4	12	65%	35%	293	100%	293	15	-	-	4	25	N/A	34	4.1	N/A	2,774	-	-	3.3	4	38	9.0	0.6	2.1	13
Condensing DHW Boiler	2	17	2.0	19	17	36	53%	47%	2,476	100%	2,476	25	-	-	1	295	N/A	373	44.7	N/A	30,540	-	-	15.5	17	418	24.6	0.8	8.2	259
Condensing DHW Heater	2	2	2.0	4	2	6	67%	33%	216	100%	216	10	-	-	4	14	N/A	19	2.3	N/A	1,559	-	-	3.4	2	21	10.5	0.6	2.3	8
Drainwater Heat Recovery	2	18	3	20	18	38	53%	47%	886	100%	886	20	-	-	4	93	N/A	120	14.5	N/A	9,858	-	-	4.6	18	134	7.7	0.7	2.5	55
Retrofit																														
Near Condensing Boiler	10	225	31	255	225	480	53%	47%	9,750	100%	9,750	25	-	-	4	1,161	N/A	1,471	176.2	N/A	120,261	-	-	4.5	225	1,647	7.3	0.7	2.4	681
Condensing Boiler	4	173	16	189	173	362	52%	48%	6,132	100%	6,132	25	-	-	5	730	N/A	925	110.8	N/A	75,635	-	-	3.9	173	1,036	6.0	0.7	2.0	368
Building Recommissioning	4	128	46	174	128	302	58%	42%	3,900	100%	3,900	10	1,800	-	11	248	1,722	339	42.5	739	28,195	13,248	-	1.4	128	1,120	8.8	0.5	6.5	1,668
Next Generation Building Automation System	1	40	7	47	40	87	54%	46%	487	100%	487	10	225	-	25	31	215	42	5.3	92	3,521	1,656	-	0.7	40	140	3.5	0.3	2.8	159
High Efficiency Roof Top Unit	1	5	3	8	5	12	63%	37%	122	100%	122	20	-	-	9	13	N/A	16	2.0	N/A	1,355	-	-	1.7	5	18	4.1	0.5	1.1	1
Instantaneous DHW Heaters	6	6	34	41	6	47	87%	13%	439	100%	439	15	-	-	11	38	N/A	50	6.2	N/A	4,162	-	-	0.9	6	57	9.0	0.4	0.8	(9)
Condensing DHW Boiler	5	43	15	58	43	100	58%	43%	6,190	100%	6,190	25	-	-	1	737	N/A	934	111.8	N/A	76,351	-	-	12.8	43	1,046	24.6	0.7	7.4	637
Condensing DHW Heater	6	6	18	24	6	30	80%	20%	647	100%	647	10	-	-	6	41	N/A	56	7.0	N/A	4,676	-	-	1.7	6	63	10.5	0.5	1.4	11
2010 Total Commercial	54	1,422	249	1,671	1,511	3,182			39,434		39,434		5,069	-	7	4,366	6,996	5,570	670	3,003	456,286	53,816	-	2.6	1,511	9,243	6.1	0.6	3.6	8,180

SHEET LABELS

Residential

New Construction		
	EE Building Design (30% Large)	**EnerEffBldg Large**
	EE Building Design (30% Small)	**EnerEffBldg Small**
	EE Building Design (60%)	**EEBldg 60%**
	High Performance Glazing HIT	**HP Glazing Unit**
	Near Condensing Boiler	**NearCond Boilers**
	Condensing Boiler	**Cond Boilers**
	Instantaneous DHW Heater	**Inst DHW Heaters**
	Condensing DHW Boiler	**Cond DHW Boilers**
	Condensing DHW Heater	**Cond DHW Heaters**
	Drainwater Heat Recovery	**Drainwater Heat Rec**
Retrofit		
	Near Condensing Boiler	**Retrofit NearCondBoilers**
	Condensing Boiler	**Retrofit CondBoilers**
	Building Recommissioning	**Retrofit Bldg Re-Comm**
	Next Generation Building Automation System	**Retrofit NextGenBAS**
	High Efficiency Roof Top Unit	**Retrofit HE Roof Top**
	Instantaneous DHW Heaters	**Retrofit Inst DHW Heaters**
	Condensing DHW Boiler	**Retrofit Cond DHW Boilers**
	Condensing DHW Heater	**Retrofit Cond DHW Heaters**

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for EE Building Design (30% Large)

PER MEASURE

Total Cost	$ 260,000		
Incentive	$ 130,000	114874.4329	Present Value accounts for any implementation lag
Participant	$ 130,000		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	2	Years		
Energy Savings per installation	1504.0	GJ	1,320	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	2030.0	GJ	541,992	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1	1	0	0	1	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,096	1,320	-	-	1,320	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	1,096	1,320	-	-	1,320	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	450,208	541,992	-	-	541,992	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 157,161	$ 157,161	$ -	$ -	$ 157,161	
Utility Program Costs						
DSM Incentives		$ 114,874	$ -	$ -	$ 114,874	Including Implementation Lag
Administration		$ 18,333	$ -	$ -	$ 18,333	
Subtotal	$ 110,649	$ 133,207	$ -	$ -	$ 133,207	
Participants' Net Costs						
Incremental Cost		$ 130,000	$ -	$ -	$ 130,000	
Subtotal	$ 107,985	$ 130,000	$ -	$ -	$ 130,000	
Alternate Savings - Net						
Energy (Purchases)		$ 900,703	$ -	$ -	$ 900,703	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 900,703	$ 900,703	$ -	$ -	$ 900,703	
Net Present Benefit (Cost)	$ 839,230	$ 794,657	$ -	$ -	$ 794,657	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.8**		-	-	**4.0**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 16.17**		**$ -**	**$ -**	**$ 16.17**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for EE Building Design (30% Small)

PER MEASURE

Total Cost	$ 95,000		
Incentive	**$ 47,500**	$41,973	Present Value accounts for any implementation lag
Participant	**$ 47,500**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	**2**	Years		
Energy Savings per installation	**550.0**	GJ	486	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**709.0**	GJ	189,297	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1	1	**0**	**0**	**1**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	404	486	-	-	486	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	404	486	-	-	486	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	157,240	189,297	-	-	189,297	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 57,871	$ 57,871	$ -	$ -	$ 57,871	
Utility Program Costs						
DSM Incentives		$ 41,973	$ -	$ -	$ 41,973	Including Implementation Lag
Administration		$ 15,833	**$ -**	**$ -**	**$ 15,833**	
Subtotal	$ 48,017	$ 57,806	$ -	$ -	$ 57,806	
Participants' Net Costs						
Incremental Cost		$ 47,500	$ -	$ -	$ 47,500	
Subtotal	$ 39,456	$ 47,500	$ -	$ -	$ 47,500	
Alternate Savings - Net						
Energy (Purchases)		$ 314,580	$ -	$ -	$ 314,580	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 314,580	$ 314,580	$ -	$ -	$ 314,580	
Net Present Benefit (Cost)	$ 284,978	$ 267,145	$ -	$ -	$ 267,145	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.3**		-	-	**3.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 17.57**		**$ -**	**$ -**	**$ 17.57**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for EE Building Design (60%)

PER MEASURE

Total Cost	$ 1,000,000			
Incentive	**$ 500,000**		$441,825	Present Value accounts for any implementation lag
Participant	**$ 500,000**			

Annual Impact Per Measure				Average Annnual Energy Savings per Measure
Time to impementation	**2**	Years		
Energy Savings per installation	**3007.0**	GJ	2,657	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**8122.0**	GJ	2,168,504	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1	1	**0**	**0**	**1**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	2,207	2,657	-	-	2,657	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	2,207	2,657	-	-	2,657	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	1,801,276	2,168,504	-	-	2,168,504	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 316,396	$ 316,396	$ -	$ -	$ 316,396	
Utility Program Costs						
DSM Incentives		$ 441,825	$ -	$ -	$ 441,825	Including Implementation Lag
Administration		$ 23,333	**$ -**	**$ -**	**$ 23,333**	
Subtotal	$ 386,385	$ 465,158	$ -	$ -	$ 465,158	
Participants' Net Costs						
Incremental Cost		$ 500,000	$ -	$ -	$ 500,000	
Subtotal	$ 415,327	$ 500,000	$ -	$ -	$ 500,000	
Alternate Savings - Net						
Energy (Purchases)		$ 3,603,698	$ -	$ -	$ 3,603,698	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 3,603,698	$ 3,603,698	$ -	$ -	$ 3,603,698	
Net Present Benefit (Cost)	$ 3,118,382	$ 2,954,936	$ -	$ -	$ 2,954,936	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**4.9**		-	-	**4.1**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 29.45**		**$ -**	**$ -**	**$ 29.45**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for High Performance Glazing HIT

PER MEASURE

Total Cost	$ 160,000		
Incentive	$ 80,000	$70,692	Present Value accounts for any implementation lag
Participant	$ 80,000		

Annual Impact Per Measure				Average Annnual Energy Savings per Measure
Time to impementation	2	Years		
Energy Savings per installation	640.0	GJ	566	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	540.0	GJ	144,175	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1	1	0	0	1	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	470	566	-	-	566	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	470	566	-	-	566	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	119,760	144,175	-	-	144,175	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 67,341	$ 67,341	$ -	$ -	$ 67,341	
Utility Program Costs						
DSM Incentives		$ 70,692	$ -	$ -	$ 70,692	Including Implementation Lag
Administration		$ -	$ -	$ -	$ -	
Subtotal	$ 58,721	$ 70,692	$ -	$ -	$ 70,692	
Participants' Net Costs						
Incremental Cost		$ 80,000	$ -	$ -	$ 80,000	
Subtotal	$ 66,452	$ 80,000	$ -	$ -	$ 80,000	
Alternate Savings - Net						
Energy (Purchases)		$ 239,596	$ -	$ -	$ 239,596	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 239,596	$ 239,596	$ -	$ -	$ 239,596	
Net Present Benefit (Cost)	$ 181,764	$ 156,244	$ -	$ -	$ 156,244	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	2.5		-	-	2.0	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 21.60**		$ -	$ -	**$ 21.60**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Near Condensing Boiler

PER MEASURE

Total Cost	$ 36,600		
Incentive	$ 18,300	No Lag	Present Value accounts for any implementation lag
Participant	$ 18,300		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	640.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	3	1	1	1	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,699	1,920	640	640	640	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	1,699	1,920	640	640	640	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 227,510	$ 227,510	$ 75,761	$ 75,542	$ 76,207	
Utility Program Costs						
DSM Incentives		$ 54,900	$ 18,300	$ 18,300	$ 18,300	Including Implementation Lag
Administration		$ 23,649	$ 9,083	$ 7,283	$ 7,283	
Subtotal	$ 69,598	$ 78,549	$ 27,383	$ 25,583	$ 25,583	
Participants' Net Costs						
Incremental Cost		$ 54,900	$ 18,300	$ 18,300	$ 18,300	
Subtotal	$ 48,574	$ 54,900	$ 18,300	$ 18,300	$ 18,300	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 109,338	$ 94,061	$ 30,078	$ 31,659	$ 32,324	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	1.9		1.7	1.7	1.7	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 5.64		$ 5.79	$ 5.56	$ 5.56	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Condensing Boiler

PER MEASURE

Total Cost	$ 69,200			
Incentive	**$ 34,600**		No Lag	Present Value accounts for any implementation lag
Participant	**$ 34,600**			

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**1114.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	4	**1**	**1**	**2**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	3,882	4,456	1,114	1,114	2,228	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	3,882	4,456	1,114	1,114	2,228	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 528,658	$ 528,658	$ 131,871	$ 131,490	$ 265,297	
Utility Program Costs						
DSM Incentives		$ 138,400	$ 34,600	$ 34,600	$ 69,200	Including Implementation Lag
Administration		$ 7,291	**$ 2,083**	**$ 2,083**	**$ 3,125**	
Subtotal	$ 126,975	$ 145,691	$ 36,683	$ 36,683	$ 72,325	
Participants' Net Costs						
Incremental Cost		$ 138,400	$ 34,600	$ 34,600	$ 69,200	
Subtotal	$ 120,580	$ 138,400	$ 34,600	$ 34,600	$ 69,200	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 281,102	$ 244,567	$ 60,588	$ 60,207	$ 123,772	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.1**		**1.8**	**1.8**	**1.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.17**		**$ 5.19**	**$ 5.19**	**$ 5.15**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Instantaneous DHW Heater

PER MEASURE

Total Cost	$ 2,100		
Incentive	$ 1,050	No Lag	Present Value accounts for any implementation lag
Participant	$ 1,050		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	73.2	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	15	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	8	9	2	3	4	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	575	659	146	220	293	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	575	659	146	220	293	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ 56,896	$ 56,896	$ 12,700	$ 18,870	$ 25,326	
Utility Program Costs						
DSM Incentives		$ 9,450	$ 2,100	$ 3,150	$ 4,200	Including Implementation Lag
Administration		$ 7,500	$ 1,500	$ 2,500	$ 3,500	
Subtotal	$ 14,773	$ 16,950	$ 3,600	$ 5,650	$ 7,700	
Participants' Net Costs						
Incremental Cost		$ 9,450	$ 2,100	$ 3,150	$ 4,200	
Subtotal	$ 8,246	$ 9,450	$ 2,100	$ 3,150	$ 4,200	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 33,877	$ 30,496	$ 7,000	$ 10,070	$ 13,426	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	2.5		2.2	2.1	2.1	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 4.23		$ 4.11	$ 4.23	$ 4.29	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Condensing DHW Boiler

PER MEASURE

Total Cost	$ 17,000			
Incentive	$ 8,500		No Lag	Present Value accounts for any implementation lag
Participant	$ 8,500			

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	1238.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	4	1	1	2	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	4,314	4,952	1,238	1,238	2,476	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	4,314	4,952	1,238	1,238	2,476	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 587,503	$ 587,503	$ 146,550	$ 146,126	$ 294,827	
Utility Program Costs						
DSM Incentives		$ 34,000	$ 8,500	$ 8,500	$ 17,000	Including Implementation Lag
Administration		$ 4,000	$ 1,000	$ 1,000	$ 2,000	
Subtotal	$ 33,107	$ 38,000	$ 9,500	$ 9,500	$ 19,000	
Participants' Net Costs						
Incremental Cost		$ 34,000	$ 8,500	$ 8,500	$ 17,000	
Subtotal	$ 29,622	$ 34,000	$ 8,500	$ 8,500	$ 17,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 524,773	$ 515,503	$ 128,550	$ 128,126	$ 258,827	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**9.4**		**8.1**	**8.1**	**8.2**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 1.18**		**$ 1.18**	**$ 1.18**	**$ 1.18**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Condensing DHW Heater

PER MEASURE

Total Cost	$ 2,000		
Incentive	**$ 1,000**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 1,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	**-**	Years		
Energy Savings per installation	**107.8**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**10**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	4	**1**	**1**	**2**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	376	431	108	108	216	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	376	431	108	108	216	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$64.83	$63.53	$63.61	
Energy Purchases	$ 27,551	$ 27,551	$ 6,988	$ 6,848	$ 13,714	
Utility Program Costs						
DSM Incentives		$ 4,000	$ 1,000	$ 1,000	$ 2,000	Including Implementation Lag
Administration		$ 4,000	**$ 1,000**	**$ 1,000**	**$ 2,000**	
Subtotal	$ 6,970	$ 8,000	$ 2,000	$ 2,000	$ 4,000	
Participants' Net Costs						
Incremental Cost		$ 4,000	$ 1,000	$ 1,000	$ 2,000	
Subtotal	$ 3,485	$ 4,000	$ 1,000	$ 1,000	$ 2,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 17,096	$ 15,551	$ 3,988	$ 3,848	$ 7,714	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.6**		**2.3**	**2.3**	**2.3**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.85**		**$ 3.85**	**$ 3.85**	**$ 3.85**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
NEW

Measure Data for Drainwater Heat Recovery

PER MEASURE

Total Cost	$ 17,500		
Incentive	$ 8,750	No Lag	Present Value accounts for any implementation lag
Participant	$ 8,750		

Annual Impact Per Measure				
			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	443.1	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	20	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	3	4	1	1	2	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,544	1,772	443	443	886	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	1,544	1,772	443	443	886	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$104.27	$103.83	$104.75	
Energy Purchases	$ 185,038	$ 185,038	$ 46,203	$ 46,007	$ 92,828	
Utility Program Costs						
DSM Incentives		$ 35,000	$ 8,750	$ 8,750	$ 17,500	Including Implementation Lag
Administration		$ 5,667	$ 1,542	$ 1,542	$ 2,583	
Subtotal	$ 35,451	$ 40,667	$ 10,292	$ 10,292	$ 20,083	
Participants' Net Costs						
Incremental Cost		$ 35,000	$ 8,750	$ 8,750	$ 17,500	
Subtotal	$ 30,494	$ 35,000	$ 8,750	$ 8,750	$ 17,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.491 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 119,093	$ 109,371	$ 27,161	$ 26,965	$ 55,245	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.8**		**2.4**	**2.4**	**2.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.84**		**$ 3.86**	**$ 3.86**	**$ 3.81**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Near Condensing Boiler

PER MEASURE

Total Cost	$ 44,900			
Incentive	$ 22,450		No Lag	Present Value accounts for any implementation lag
Participant	$ 22,450			

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	975.0	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	24	27	8	9	10	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	23,185	26,325	7,800	8,775	9,750	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	23,185	26,325	7,800	8,775	9,750	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 3,120,053	$ 3,120,053	$ 923,333	$ 1,035,748	$ 1,160,972	
Utility Program Costs						
DSM Incentives		$ 606,150	$ 179,600	$ 202,050	$ 224,500	Including Implementation Lag
Administration		$ 88,523	$ 28,624	$ 28,908	$ 30,991	
Subtotal	$ 612,047	$ 694,673	$ 208,224	$ 230,958	$ 255,491	
Participants' Net Costs						
Incremental Cost		$ 606,150	$ 179,600	$ 202,050	$ 224,500	
Subtotal	$ 533,852	$ 606,150	$ 179,600	$ 202,050	$ 224,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 1,974,155	$ 1,819,230	$ 535,509	$ 602,740	$ 680,981	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.7**		**2.4**	**2.4**	**2.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.01**		**$ 4.03**	**$ 4.00**	**$ 3.99**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Condensing Boiler

PER MEASURE

Total Cost	$ 86,500		
Incentive	**$ 43,250**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 43,250**		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	**1533.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**25**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	7	8	**1**	**3**	**4**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	10,599	12,264	1,533	4,599	6,132	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	10,599	12,264	1,533	4,599	6,132	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 1,454,471	$ 1,454,471	$ 181,470	$ 542,838	$ 730,162	
Utility Program Costs						
DSM Incentives		$ 346,000	$ 43,250	$ 129,750	$ 173,000	Including Implementation Lag
Administration		$ 32,666	**$ 4,083**	**$ 12,250**	**$ 16,333**	
Subtotal	$ 327,243	$ 378,666	$ 47,333	$ 142,000	$ 189,333	
Participants' Net Costs						
Incremental Cost		$ 346,000	$ 43,250	$ 129,750	$ 173,000	
Subtotal	$ 299,013	$ 346,000	$ 43,250	$ 129,750	$ 173,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 828,215	$ 729,805	$ 90,887	$ 271,088	$ 367,829	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.3**		**2.0**	**2.0**	**2.0**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.79**		**$ 4.79**	**$ 4.79**	**$ 4.79**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Building Recommissioning

PER MEASURE

Total Cost	$ 64,000		
Incentive	**$ 32,000**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 32,000**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	**975.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**1620.0**	GJ	450,000	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**10**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	7	8	**2**	**2**	**4**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	6,796	7,800	1,950	1,950	3,900	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	6,796	7,800	1,950	1,950	3,900	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	3,136,485	3,600,000	900,000	900,000	1,800,000	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$64.83	$63.53	$63.61	
Energy Purchases	$ 498,366	$ 498,366	$ 126,412	$ 123,882	$ 248,071	
Utility Program Costs						
DSM Incentives		$ 256,000	$ 64,000	$ 64,000	$ 128,000	Including Implementation Lag
Administration		$ 98,667	**$ 26,167**	**$ 26,167**	**$ 46,333**	
Subtotal	$ 309,246	$ 354,667	$ 90,167	$ 90,167	$ 174,333	
Participants' Net Costs						
Incremental Cost		$ 256,000	$ 64,000	$ 64,000	$ 128,000	
Subtotal	$ 223,039	$ 256,000	$ 64,000	$ 64,000	$ 128,000	
Alternate Savings - Net						
Energy (Purchases)		$ 3,444,521	$ 861,130	$ 861,130	$ 1,722,261	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 3,444,521	$ 3,444,521	$ 861,130	$ 861,130	$ 1,722,261	
Net Present Benefit (Cost)	$ 3,410,602	$ 3,332,220	$ 833,376	$ 830,845	$ 1,667,999	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**7.4**		**6.4**	**6.4**	**6.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 10.83**		**$ 10.94**	**$ 10.94**	**$ 10.72**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Next Generation Building Automation System

PER MEASURE

Total Cost	$ 80,000		
Incentive	**$ 40,000**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 40,000**		

Annual Impact Per Measure

Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	**487.0**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**810.0**	GJ	225,000	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**10**	Years		Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	2	2	**0**	**1**	**1**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	835	974	-	487	487	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	835	974	-	487	487	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	385,718	450,000	-	225,000	225,000	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$64.83	$63.53	$63.61	
Energy Purchases	$ 61,916	$ 61,916	$ -	$ 30,939	$ 30,977	
Utility Program Costs						
DSM Incentives		$ 80,000	$ -	$ 40,000	$ 40,000	Including Implementation Lag
Administration		$ 15,084	**$ 1,000**	**$ 7,042**	**$ 7,042**	
Subtotal	$ 81,584	$ 95,084	$ 1,000	$ 47,042	$ 47,042	
Participants' Net Costs						
Incremental Cost		$ 80,000	$ -	$ 40,000	$ 40,000	
Subtotal	$ 68,572	$ 80,000	$ -	$ 40,000	$ 40,000	
Alternate Savings - Net						
Energy (Purchases)		$ 430,565	$ -	$ 215,283	$ 215,283	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 430,565	$ 430,565	$ -	$ 215,283	$ 215,283	
Net Present Benefit (Cost)	$ 342,325	$ 317,397	$ (1,000)	$ 159,179	$ 159,218	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.3**		**-**	**2.8**	**2.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 24.88**		**$ -**	**$ 24.72**	**$ 24.72**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for High Efficiency Roof Top Unit

PER MEASURE

Total Cost	$ 9,000		
Incentive	**$ 4,500**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 4,500**		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure		
Time to impementation	**-**	Years			
Energy Savings per installation	**121.8**	GJ		-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%			Net-to-Gross
Alternate Energy Impact	**0.0**	GJ		-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a		-	kW/a; Present Value accounts for any lag
Measure Lifetime	**20**	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	2	2	**0**	**1**	**1**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	209	244	-	122	122	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	209	244	-	122	122	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$104.27	$103.83	$104.75	
Energy Purchases	$ 25,405	$ 25,405	$ -	$ 12,647	$ 12,758	
Utility Program Costs						
DSM Incentives		$ 9,000	$ -	$ 4,500	$ 4,500	Including Implementation Lag
Administration		$ 7,084	**$ 1,000**	**$ 3,042**	**$ 3,042**	
Subtotal	$ 13,869	$ 16,084	$ 1,000	$ 7,542	$ 7,542	
Participants' Net Costs						
Incremental Cost		$ 9,000	$ -	$ 4,500	$ 4,500	
Subtotal	$ 7,714	$ 9,000	$ -	$ 4,500	$ 4,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.491 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 3,821	$ 321	$ (1,000)	$ 605	$ 716	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.2**		**-**	**1.1**	**1.1**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 9.29**		**$ -**	**$ 8.89**	**$ 8.89**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Instantaneous DHW Heaters

PER MEASURE

Total Cost	$ 2,100		
Incentive	**$ 1,050**	No Lag	Present Value accounts for any implementation lag
Participant	**$ 1,050**		

Annual Impact Per Measure — Average Annnual Energy Savings per Measure

Time to impementation	-	Years		
Energy Savings per installation	**73.2**	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	**0%**	100%		Net-to-Gross
Alternate Energy Impact	**0.0**	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	**15**	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	10	12	**2**	**4**	**6**	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	761	878	146	293	439	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	761	878	146	293	439	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ 75,849	$ 75,849	$ 12,700	$ 25,160	$ 37,990	
Utility Program Costs						
DSM Incentives		$ 12,600	$ 2,100	$ 4,200	$ 6,300	Including Implementation Lag
Administration		$ 78,400	**$ 22,000**	**$ 22,200**	**$ 34,200**	
Subtotal	$ 79,624	$ 91,000	$ 24,100	$ 26,400	$ 40,500	
Participants' Net Costs						
Incremental Cost		$ 12,600	$ 2,100	$ 4,200	$ 6,300	
Subtotal	$ 10,919	$ 12,600	$ 2,100	$ 4,200	$ 6,300	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ (14,694)	$ (27,751)	$ (13,500)	$ (5,440)	$ (8,810)	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**0.8**		**0.5**	**0.8**	**0.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 12.55**		**$ 18.89**	**$ 11.03**	**$ 11.25**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Condensing DHW Boiler

PER MEASURE

Total Cost	$ 17,000		
Incentive	$ 8,500	No Lag	Present Value accounts for any implementation lag
Participant	$ 8,500		

Annual Impact Per Measure			Average Annnual Energy Savings per Measure
Time to impementation	-	Years	
Energy Savings per installation	1238.0	GJ	- Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%	Net-to-Gross
Alternate Energy Impact	0.0	GJ	- kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	- kW/a; Present Value accounts for any lag
Measure Lifetime	25	Years	Estimated lifespan of measure

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	9	10	2	3	5	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	10,751	12,380	2,476	3,714	6,190	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	10,751	12,380	2,476	3,714	6,190	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$118.38	$118.03	$119.07	
Energy Purchases	$ 1,468,546	$ 1,468,546	$ 293,099	$ 438,378	$ 737,069	
Utility Program Costs						
DSM Incentives		$ 85,000	$ 17,000	$ 25,500	$ 42,500	Including Implementation Lag
Administration		$ 30,000	$ 6,000	$ 9,000	$ 15,000	
Subtotal	$ 99,869	$ 115,000	$ 23,000	$ 34,500	$ 57,500	
Participants' Net Costs						
Incremental Cost		$ 85,000	$ 17,000	$ 25,500	$ 42,500	
Subtotal	$ 73,816	$ 85,000	$ 17,000	$ 25,500	$ 42,500	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.662 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 1,294,860	$ 1,268,546	$ 253,099	$ 378,378	$ 637,069	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	8.5		7.3	7.3	7.4	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 1.31		$ 1.31	$ 1.31	$ 1.31	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
COMMERCIAL
RETROFIT

Measure Data for Condensing DHW Heater

PER MEASURE

Total Cost	$ 2,000			
Incentive	$ 1,000		No Lag	Present Value accounts for any implementation lag
Participant	$ 1,000			

Annual Impact Per Measure			Average Annnual Energy Savings per Measure	
Time to impementation	-	Years		
Energy Savings per installation	107.8	GJ	-	Present Value accounts for any implementation lag
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	0.0	GJ	-	kWh; Present Value accounts for any lag
Alternate Capacity Impact		kW/a	-	kW/a; Present Value accounts for any lag
Measure Lifetime	10	Years	Estimated lifespan of measure	

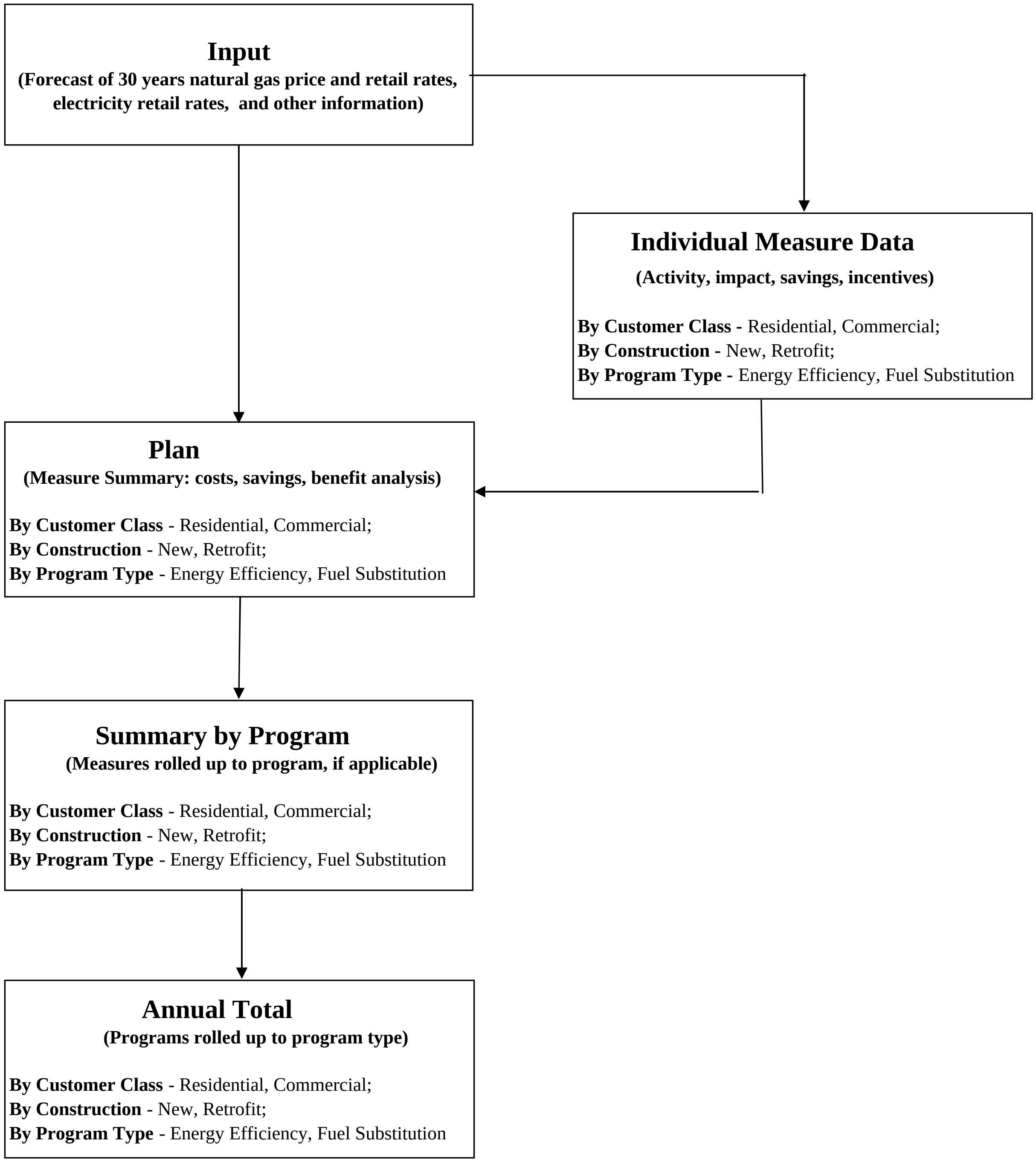
ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	10	12	2	4	6	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,121	1,294	216	431	647	Extension of Unit Savings x No. of Upgrades (Including Lag)
Net Energy Savings (GJ)	1,121	1,294	216	431	647	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	-	-	-	-	-	Other Utility Billed energy impact (Including any lag)
Alternate Capacity Impact (Increase) (kW/a)	-	-	-	-	-	Other Utility Billed capacity impact (Including any lag)

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$64.83	$63.53	$63.61	
Energy Purchases	$ 82,512	$ 82,512	$ 13,977	$ 27,394	$ 41,142	
Utility Program Costs						
DSM Incentives		$ 12,000	$ 2,000	$ 4,000	$ 6,000	Including Implementation Lag
Administration		$ 36,000	$ 6,000	$ 12,000	$ 18,000	
Subtotal	$ 41,594	$ 48,000	$ 8,000	$ 16,000	$ 24,000	
Participants' Net Costs						
Incremental Cost		$ 12,000	$ 2,000	$ 4,000	$ 6,000	
Subtotal	$ 10,399	$ 12,000	$ 2,000	$ 4,000	$ 6,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$0.957 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 30,519	$ 22,512	$ 3,977	$ 7,394	$ 11,142	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.6**		**1.4**	**1.4**	**1.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 6.42**		**$ 6.42**	**$ 6.42**	**$ 6.42**	Informational (for comparison with supply options)

Table of Contents

Sheet Name	Description	MEASURE NAME	PROGRAM NAME
Annual Total	Program Type Summary - costs, savings, and benefit analysis		
Summary by Program	Program Summary - costs, savings, and benefit analysis - annual and total		
Plan	Measures Summary - costs, savings, and benefit analysis - annual		
Input	30 years Natural Gas Price, and other inputs to the model		
FP	Measure data and benefit analysis for Fireplaces (New Construction)	EE EnerChoice Fireplace	EE EnerChoice Fireplace
Estar Clothes	Measure data and benefit analysis for Clothes Washers (New Construction)	EE E* Clothes Washer	EE E* Hot Water Saving Appliances
Estar Dish	Measure data and benefit analysis for Dish Washers (New Construction)	EE E* Dishwasher	EE E* Hot Water Saving Appliances
FS NG DHW	Measure data and benefit analysis for Natural Gas Water Heating (New Construction)	FS Natural Gas DHW	FS Natural Gas DHW
FS Range	Measure data and benefit analysis for LB Ranges (New Construction)	FS Gas Cooking Range	FS Gas Cooking Range
FS Dryer	Measure data and benefit analysis for LB Dryers (New Construction)	FS Gas Clothes Dryer	FS Gas Clothes Dryer
Retrofit EE Furnace	Measure data and benefit analysis for Furnace Upgrade (Retrofit)	EE E* Furnace Upgrade	EE E* Furnace Upgrade
Retrofit EE FP	Measure data and benefit analysis for Fireplaces (Retrofit)	EE EnerChoice Fireplace	EE EnerChoice Fireplace
Retrofit Estar Dish	Measure data and benefit analysis for Dish Washers (Retrofit)	EE E * Dishwasher	EE E* Hot Water Saving Appliances
Retrofit Estar Clothes	Measure data and benefit analysis for Clothes Washers (Retrofit)	EE E* Clothes Washer	EE E* Hot Water Saving Appliances
Retrofit FS Furnace	Measure data and benefit analysis for Furnace Fuel Switching (Retrofit)	FS E* Furnace Upgrade	FS E* Furnace Upgrade
Retrofit FS FP	Measure data and benefit analysis for Fireplace Fuel Switching (Retrofit)	FS EnerChoice Fireplace	FS EnerChoice Fireplace
Retrofit FS Range	Measure data and benefit analysis for Ranges (Retrofit)	FS Gas Cooking Range	FS Gas Cooking Range
Retrofit FS Dryer	Measure data and benefit analysis for Dryers (Retrofit)	FS Gas Clothes Dryer	FS Gas Clothes Dryer


Input
(Forecast of 30 years natural gas price and retail rates, electricity retail rates, and other information)
Individual Measure Data
(Activity, impact, savings, incentives)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Plan
(Measure Summary: costs, savings, benefit analysis)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Summary by Program
(Measures rolled up to program, if applicable)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution
Annual Total
(Programs rolled up to program type)
By Customer Class - Residential, Commercial;
By Construction - New, Retrofit;
By Program Type - Energy Efficiency, Fuel Substitution

TERASEN GAS VANCOUVER ISLAND

		PROGRAM									ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Customer Benefits (Costs)			Program Net Savings				Participant					
		Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas				Natural Gas		TRC Net Benefits
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Rate Impact	Total Resource	($'000s)
2008																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	522	63	67	130	7	137	95%	5%	2,859	2,859	26	-	**4.9**	244	32	375	35	15	26,703	244	-	1.9	7	426	60.0	0.5	2.0	139
Fuel Substitution	452	123	92	215	-6	210	103%	-3%	-6,903	-6,903	1,054	-	**FS**	-467	1,050	-725	-67	512	(51,833)	8,076	-	FS	792	517	0.7	1.1	1.6	374
Retrofit																												
Energy Efficiency	338	23	30	53	19	72	74%	26%	1,170	1,170	40	-	**4.8**	100	48	154	15	23	10,983	368	-	1.9	19	192	10.1	0.5	2.1	76
Fuel Substitution	1,200	278	183	461	180	641	72%	28%	-36,900	-36,900	9,785	-	**FS**	-3,562	13,668	-5,420	-511	6,662	(384,299)	105,142	-	FS	6,111	6,662	1.1	1.3	3.3	9,466
Subtotals																												
Residential Energy Efficiency	860	86	97	183	26	209	88%	12%	4,029	4,029	66	-	**4.9**	344	80	530	50	39	37,686	612	-	**1.9**	**26**	**618**	**23.7**	**0.5**	**2.0**	**215**
Residential Fuel Substitution	1,652	401	276	676	174	851	80%	20%	-43,803	-43,803	10,839	-	**FS**	-4,029	14,718	-6,145	-578	7,174	(436,132)	113,218	-	**FS**	**6,897**	**7,174**	**1.0**	**1.3**	**3.0**	**9,839**
2008 Total Residential	**2,512**	**487**	**372**	**859**	**200**	**1,060**	**81%**	**19%**	**-39,774**	**-39,774**	**10,905**	**-**	**FS**	**-3,684**	**14,798**	**-5,615**	**-529**	**7,212**	**(398,446)**	**113,830**	**-**							
2009																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	943	124	32	156	12	167	93%	7%	5,501	5,501	49	-	**3.0**	466	60	724	73	29	51,526	458	-	3.0	12	826	70.6	0.5	3.1	359
Fuel Substitution	731	187	36	223	-12	211	105%	-5%	-10,564	-10,564	1,615	-	**FS**	-710	1,628	-1,122	-113	793	(80,210)	12,521	-	FS	1,235	805	0.7	1.2	1.8	706
Retrofit																												
Energy Efficiency	625	45	22	66	37	103	64%	36%	2,233	2,233	78	-	**3.2**	191	94	296	30	46	21,031	721	-	2.9	37	371	10.1	0.5	2.8	181
Fuel Substitution	1,781	371	162	533	180	713	75%	25%	-41,580	-41,580	10,518	-	**FS**	-3,954	14,602	-6,060	-607	7,117	(429,787)	112,324	-	FS	6,847	7,117	1.0	1.4	3.1	9,935
Subtotals																												
Residential Energy Efficiency	1,568	168	54	222	48	270	82%	18%	7,734	7,734	127	-	**3.1**	657	153	1,020	102	75	72,557	1,178	-	**3.0**	**48**	**1,197**	**24.7**	**0.5**	**3.0**	**540**
Residential Fuel Substitution	2,512	558	198	756	168	924	82%	18%	-52,144	-52,144	12,133	-	**FS**	-4,665	16,230	-7,182	-720	7,910	(509,997)	124,844	-	**FS**	**8,071**	**7,910**	**1.0**	**1.3**	**2.9**	**10,641**
2009 Total Residential	**4,080**	**726**	**252**	**978**	**217**	**1,195**	**82%**	**18%**	**-44,410**	**-44,410**	**12,260**	**-**	**FS**	**-4,008**	**16,383**	**-6,162**	**-618**	**7,985**	**(437,441)**	**126,023**	**-**							
2010																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	1,507	189	43	232	21	253	92%	8%	8,479	8,479	88	-	**2.9**	723	106	1,114	118	52	79,308	818	-	3.1	21	1,284	61.4	0.5	3.3	576
Fuel Substitution	1,162	268	75	343	-23	320	107%	-7%	-15,488	-15,488	2,371	-	**FS**	-1,065	2,434	-1,674	-179	1,186	(119,646)	18,724	-	FS	1,854	1,209	0.7	1.2	1.8	1,049
Retrofit																												
Energy Efficiency	988	68	29	97	56	154	63%	37%	3,455	3,455	118	-	**3.0**	297	142	456	48	69	32,468	1,095	-	3.0	56	574	10.2	0.5	2.9	285
Fuel Substitution	2,350	463	128	591	180	771	77%	23%	-46,070	-46,070	11,217	-	**FS**	-4,387	15,494	-6,675	-699	7,551	(473,479)	119,181	-	FS	7,554	7,551	1.0	1.3	3.0	10,336
Subtotals																												
Residential Energy Efficiency	2,495	257	72	329	77	407	81%	19%	11,934	11,934	206	-	**2.9**	1,019	249	1,571	166	121	111,776	1,913	-	**3.1**	**77**	**1,858**	**24.0**	**0.5**	**3.1**	**861**
Residential Fuel Substitution	3,512	731	203	934	157	1,090	86%	14%	-61,558	-61,558	13,588	-	**FS**	-5,452	17,928	-8,349	-878	8,738	(593,125)	137,905	-	**FS**	**9,385**	**8,738**	**0.9**	**1.3**	**2.7**	**11,386**
2010 Total Residential	**6,007**	**988**	**275**	**1,263**	**234**	**1,497**	**84%**	**16%**	**-49,624**	**-49,624**	**13,794**	**-**	**FS**	**-4,432**	**18,176**	**-6,779**	**-713**	**8,859**	**(481,349)**	**139,818**	**-**							
2008 - 2010 (NPV 2007)																												
RESIDENTIAL:																												
New Construction																												
Energy Efficiency	2,576	325	127	452	34	487	93%	7%	14,592	14,592	141	-	**2.9**	1,433	198	2,214	226	96	157,537	1,520	-	3.2	34	2,536	73.8	0.5	3.4	1,144
Fuel Substitution	2,036	504	181	684	-35	649	105%	-5%	-28,689	-28,689	4,386	-	**FS**	-2,242	5,112	-3,521	-360	2,491	(251,690)	39,321	-	FS	3,881	2,526	0.7	1.2	1.8	2,221
Retrofit																												
Energy Efficiency	1,691	118	71	189	97	287	66%	34%	5,943	5,943	205	-	**2.9**	588	284	907	92	138	64,482	2,183	-	3.1	97	1,137	11.7	0.5	3.0	585
Fuel Substitution	4,654	973	422	1,395	478	1,873	74%	26%	-109,697	-109,697	27,811	-	**FS**	-11,903	43,764	-18,156	-1,817	21,330	(1,287,565)	336,647	-	FS	20,451	21,330	1.0	1.4	3.2	29,988
Subtotals																												
Residential Energy Efficiency	**4,266**	**443**	**198**	**642**	**132**	**773**	**83%**	**17%**	**20,535**	**20,535**	**346**	**-**	**2.9**	**2,021**	**481**	**3,120**	**318**	**235**	**222,019**	**3,703**	**-**	**3.1**	**132**	**3,673**	**27.9**	**0.5**	**3.2**	**1,729**
Residential Fuel Substitution	**6,690**	**1,477**	**602**	**2,079**	**443**	**2,522**	**82%**	**18%**	**-138,387**	**-138,387**	**32,197**	**-**	**FS**	**-14,145**	**48,876**	**-21,677**	**-2,177**	**23,821**	**(1,539,255)**	**375,967**	**-**	**FS**	**24,297**	**23,821**	**1.0**	**1.3**	**2.9**	**32,209**
2008 - 2010 Total Residential	**10,956**	**1,920**	**801**	**2,721**	**575**	**3,295**	**83%**	**17%**	**-117,852**	**-117,852**	**32,543**	**-**	**FS**	**-12,124**	**49,357**	**-18,556**	**-1,859**	**24,056**	**(1,317,236)**	**379,671**	**-**							

TERASEN GAS VANCOUVER ISLAND

	Participants	PROGRAM – COSTS ($000) – Utility – Incentives	Utility – Administration	Utility – Total	Participant	Total	% Utility	% Participant	SAVINGS (GJ) – Gross	SAVINGS (GJ) – Net	ALTERNATE Impact – Energy MWh	ALTERNATE Impact – Capacity kW	NET PRESENT VALUE – Levelized Cost ($/GJ)	Utility Benefits (Costs) – Program ($'000s)	Utility Benefits (Costs) – Alternate ($'000s)	Customer Benefits (Costs) – Program ($'000s)	Customer Benefits (Costs) – Carbon Tax ($'000s)	Customer Benefits (Costs) – Alternate ($'000s)	Program Net Savings – Natural Gas (GJ)	Program Net Savings – Alternate Energy (MWh)	Program Net Savings – Alternate Capacity (kW)	BENEFIT/COST – Natural Gas Utility	Participant – Total Costs ($'000s)	Participant – Total Benefits ($'000s)	Participant – Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2008																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	280	56	28	84	-	84	100%	0%	2,324	2,324	7	-	4	202	9	310	29	4	22,021	68	-	2.4	-	343	N/A	0.5	2.5	127
EE E* Hot Water Saving Appliances	242	7	39	46	7	53	87%	13%	535	535	19	-	10	42	23	66	6	11	4,682	176	-	0.9	7	83	11.7	0.4	1.2	12
Subtotal New Constuction Energy Efficiency	**522**	**63**	**67**	**130**	**7**	**137**	**95%**	**5%**	**2,859**	**2,859**	**26**	**-**	**5**	**244**	**32**	**375**	**35**	**15**	**26,703**	**244**	**-**	**1.9**	**7**	**426**	**60.0**	**0.5**	**2.0**	**139**
FS Natural Gas DHW	336	118	73	191	-	191	100%	0%	-6,317	-6,317	961	-	FS	(409)	920	(638)	(59)	448	(45,667)	7,075	-	FS	697	448	0.6	1.1	1.5	319
FS Gas Cooking Range	39	2	17	19	(2)	17	111%	-11%	(296)	(296)	33	-	FS	(29)	46	(44)	(4)	23	(3,120)	357	-	FS	48	25	0.5	0.9	1.0	0
FS Gas Clothes Dryer	77	4	2	5	(4)	2	350%	-250%	(290)	(290)	59	-	FS	(28)	84	(43)	(4)	41	(3,047)	644	-	FS	47	45	0.9	1.3	2.8	54
Subtotal New Construction Fuel Substitution	**452**	**123**	**92**	**215**	**(6)**	**210**	**103%**	**-3%**	**-6,903**	**-6,903**	**1,054**	**-**	**FS**	**(467)**	**1,050**	**(725)**	**(67)**	**512**	**(51,833)**	**8,076**	**-**	**FS**	**792**	**517**	**0.7**	**1.1**	**1.6**	**374**
Retrofit																												
EE E* Furnace Upgrade	30	9	1	10	9	19	52%	48%	309	309	-	-	3	30	-	46	4	-	3,252	-	-	3.1	9	50	5.6	0.5	1.6	12
EE EnerChoice Fireplace	20	4	0	4	-	4	100%	0%	166	166	1	-	3	14	1	22	2	0	1,573	5	-	3.3	-	25	N/A	0.5	3.4	11
EE E* Hot Water Saving Appliances	288	10	29	39	10	49	80%	20%	695	695	39	-	6	56	47	86	8	23	6,158	363	-	1.4	10	118	11.7	0.4	2.1	54
Subtotal Retrofit Energy Efficiency	**338**	**23**	**30**	**53**	**19**	**72**	**74%**	**26%**	**1,170**	**1,170**	**40**	**-**	**5**	**100**	**48**	**154**	**15**	**23**	**10,983**	**368**	**-**	**1.9**	**19**	**192**	**10.1**	**0.5**	**2.1**	**76**
FS E* Furnace Upgrade	600	180	99	279	180	459	61%	39%	-31,920	-31,920	9,000	-	FS	(3,118)	12,668	(4,740)	(447)	6,174	(335,966)	97,448	-	FS	5,367	6,174	1.2	1.4	3.5	9,092
FS EnerChoice Fireplace	150	30	59	89	-	89	100%	0%	-2,370	-2,370	417	-	FS	(206)	526	(316)	(30)	256	(22,457)	4,047	-	FS	345	256	0.7	1.1	1.8	231
FS Gas Cooking Range	225	34	13	47	-	47	100%	0%	(1,755)	(1,755)	194	-	FS	(171)	273	(261)	(25)	133	(18,472)	2,098	-	FS	285	133	0.5	1.2	1.3	55
FS Gas Clothes Dryer	225	34	13	47	-	47	100%	0%	(855)	(855)	175	-	FS	(67)	201	(104)	(10)	98	(7,404)	1,549	-	FS	114	98	0.9	0.9	1.8	88
Subtotal Retrofit Fuel Substitution	**1,200**	**278**	**183**	**461**	**180**	**641**	**72%**	**28%**	**(36,900)**	**(36,900)**	**9,785**	**-**	**FS**	**(3,562)**	**13,668**	**(5,420)**	**(511)**	**6,662**	**(384,299)**	**105,142**	**-**	**FS**	**6,111**	**6,662**	**1.1**	**1.3**	**3.3**	**9,466**
2008 Subtotal Energy Efficiency	**860**	**86**	**97**	**183**	**26**	**209**	**88%**	**12%**	**4,029**	**4,029**	**66**	**-**	**5**	**344**	**80**	**530**	**50**	**39**	**37,686**	**612**	**-**	**1.9**	**26**	**618**	**23.7**	**0.5**	**2.0**	**215**
2008 Subtotal Fuel Substitution	**1,652**	**401**	**276**	**676**	**174**	**851**	**80%**	**20%**	**(43,803)**	**(43,803)**	**10,839**	**-**	**FS**	**(4,029)**	**14,718**	**(6,145)**	**(578)**	**7,174**	**(436,132)**	**113,218**	**-**	**FS**	**6,897**	**7,174**	**1.0**	**1.3**	**3.0**	**9,839**
2008 Total Residential	**2,512**	**487**	**372**	**859**	**200**	**1,060**	**81%**	**19%**	**(39,774)**	**(39,774)**	**10,905**	**-**	**-**	**(3,684)**	**14,798**	**(5,615)**	**(529)**	**7,212**	**(398,446)**	**113,830**	**-**	**(4.3)**	**200**	**1,068**	**5.3**	**0.8**	**10.5**	**10,054**
2009																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	559	112	14	125	-	125	100%	0%	4,640	4,640	14	-	3	399	18	618	62	9	43,964	136	-	3.2	-	689	N/A	0.5	3.3	291
EE E* Hot Water Saving Appliances	384	12	18	30	12	42	72%	28%	862	862	35	-	4	68	42	106	11	20	7,562	322	-	2.3	12	137	11.7	0.5	2.6	68
Subtotal New Constuction Energy Efficiency	**943**	**124**	**32**	**156**	**12**	**167**	**93%**	**7%**	**5,501**	**5,501**	**49**	**-**	**3**	**466**	**60**	**724**	**73**	**29**	**51,526**	**458**	**-**	**3.0**	**12**	**826**	**70.6**	**0.5**	**3.1**	**359**
FS Natural Gas DHW	500	175	24	199	-	199	100%	0%	-9,400	-9,400	1,431	-	FS	(597)	1,369	(949)	(96)	667	(67,956)	10,529	-	FS	1,045	667	0.6	1.2	1.7	573
FS Gas Cooking Range	77	4	9	13	(4)	9	142%	-42%	(585)	(585)	65	-	FS	(57)	92	(87)	(9)	45	(6,159)	704	-	FS	96	48	0.5	1.2	1.4	25
FS Gas Clothes Dryer	154	8	3	11	(8)	3	350%	-250%	(579)	(579)	119	-	FS	(56)	167	(86)	(9)	82	(6,095)	1,288	-	FS	95	89	0.9	1.3	2.8	108
Subtotal New Construction Fuel Substitution	**731**	**187**	**36**	**223**	**(12)**	**211**	**105%**	**-5%**	**-10,564**	**-10,564**	**1,615**	**-**	**FS**	**(710)**	**1,628**	**(1,122)**	**(113)**	**793**	**(80,210)**	**12,521**	**-**	**FS**	**1,235**	**805**	**0.7**	**1.2**	**1.8**	**706**
Retrofit																												
EE E* Furnace Upgrade	60	18	1	19	18	37	52%	48%	618	618	-	-	3	60	-	92	9	-	6,505	-	-	3.1	18	101	5.6	0.5	1.6	23
EE EnerChoice Fireplace	40	8	1	9	-	9	100%	0%	332	332	1	-	3	29	1	44	4	1	3,146	10	-	3.2	-	49	N/A	0.5	3.4	21
EE E* Hot Water Saving Appliances	525	19	20	38	19	57	67%	33%	1,283	1,283	77	-	3	102	92	160	16	45	11,380	711	-	2.7	19	221	11.8	0.5	3.4	137
Subtotal Retrofit Energy Efficiency	**625**	**45**	**22**	**66**	**37**	**103**	**64%**	**36%**	**2,233**	**2,233**	**78**	**-**	**3**	**191**	**94**	**296**	**30**	**46**	**21,031**	**721**	**-**	**2.9**	**37**	**371**	**10.1**	**0.5**	**2.8**	**181**
FS E* Furnace Upgrade	600	180	86	266	180	446			-31,920	-31,920	9,000	-	FS	(3,100)	12,668	(4,740)	(474)	6,174	(335,966)	97,448	-	FS	5,394	6,174	1.1	1.4	3.6	9,122
FS EnerChoice Fireplace	281	56	49	105	-	105			-4,440	-4,440	781	-	FS	(382)	986	(591)	(59)	480	(42,070)	7,581	-	FS	651	480	0.7	1.2	2.0	499
FS Gas Cooking Range	450	68	13	81	-	81	100%	0%	(3,510)	(3,510)	388	-	FS	(341)	545	(521)	(52)	266	(36,944)	4,196	-	FS	573	266	0.5	1.2	1.3	124
FS Gas Clothes Dryer	450	68	13	81	-	81	100%	0%	(1,710)	(1,710)	350	-	FS	(132)	403	(208)	(21)	196	(14,808)	3,098	-	FS	229	196	0.9	1.0	1.9	190
Subtotal Retrofit Fuel Substitution	**1,781**	**371**	**162**	**533**	**180**	**713**	**75%**	**25%**	**(41,580)**	**(41,580)**	**10,518**	**-**	**FS**	**(3,954)**	**14,602**	**(6,060)**	**(607)**	**7,117**	**(429,787)**	**112,324**	**-**	**FS**	**6,847**	**7,117**	**1.0**	**1.4**	**3.1**	**9,935**
2009 Subtotal Energy Efficiency	**1,568**	**168**	**54**	**222**	**48**	**270**	**82%**	**18%**	**7,734**	**7,734**	**127**	**-**	**3**	**657**	**153**	**1,020**	**102**	**75**	**72,557**	**1,178**	**-**	**3.0**	**48**	**1,197**	**24.7**	**0.5**	**3.0**	**540**
2009 Subtotal Fuel Substitution	**2,512**	**558**	**198**	**756**	**168**	**924**	**82%**	**18%**	**(52,144)**	**(52,144)**	**12,133**	**-**	**FS**	**(4,665)**	**16,230**	**(7,182)**	**(720)**	**7,910**	**(509,997)**	**124,844**	**-**	**FS**	**8,071**	**7,910**	**1.0**	**1.3**	**2.9**	**10,641**
2009 Total Residential	**4,080**	**726**	**252**	**978**	**217**	**1,195**	**82%**	**18%**	**(44,410)**	**(44,410)**	**12,260**	**-**	**-**	**(4,008)**	**16,383**	**(6,162)**	**(618)**	**7,985**	**(437,441)**	**126,023**	**-**	**(4.1)**	**217**	**1,205**	**5.6**	**0.8**	**10.4**	**11,181**
2010																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	839	168	19	187	-	187	100%	0%	6,964	6,964	21	-	3	602	26	928	98	13	65,985	204	-	3.2	-	1,038	N/A	0.5	3.4	442
EE E* Hot Water Saving Appliances	668	21	24	45	21	66	68%	32%	1,515	1,515	67	-	3	120	80	187	20	39	13,323	615	-	2.7	21	246	11.8	0.5	3.0	134
Subtotal New Constuction Energy Efficiency	**1,507**	**189**	**43**	**232**	**21**	**253**	**92%**	**8%**	**8,479**	**8,479**	**88**	**-**	**3**	**723**	**106**	**1,114**	**118**	**52**	**79,308**	**818**	**-**	**3.1**	**21**	**1,284**	**61.4**	**0.5**	**3.3**	**576**
FS Natural Gas DHW	700	245	58	303	-	303	100%	0%	-13,160	-13,160	2,003	-	FS	(837)	1,916	(1,328)	(143)	934	(95,139)	14,741	-	FS	1,472	934	0.6	1.2	1.7	776
FS Gas Cooking Range	154	8	11	18	(8)	11	172%	-72%	(1,170)	(1,170)	130	-	FS	(115)	183	(174)	(18)	89	(12,319)	1,408	-	FS	192	97	0.5	1.3	1.5	58
FS Gas Clothes Dryer	308	15	6	22	(15)	6	350%	-250%	(1,158)	(1,158)	238	-	FS	(113)	335	(172)	(18)	163	(12,189)	2,575	-	FS	190	179	0.9	1.3	2.8	215
Subtotal New Construction Fuel Substitution	**1,162**	**268**	**75**	**343**	**(23)**	**320**	**107%**	**-7%**	**-15,488**	**-15,488**	**2,371**	**-**	**FS**	**(1,065)**	**2,434**	**(1,674)**	**(179)**	**1,186**	**(119,646)**	**18,724**	**-**	**FS**	**1,854**	**1,209**	**0.7**	**1.2**	**1.8**	**1,049**
Retrofit																												
EE E* Furnace Upgrade	90	27	2	29	27	56	52%	48%	927	927	-	-	3	91	-	138	14	-	9,757	-	-	3.2	27	152	5.6	0.5	1.6	35
EE EnerChoice Fireplace	60	12	1	13	-	13	100%	0%	498	498	2	-	3	43	2	66	7	1	4,719	15	-	3.3	-	74	N/A	0.5	3.4	32
EE E* Hot Water Saving Appliances	838	29	26	55	29	85	65%	35%	2,030	2,030	117	-	3	163	140	252	27	68	17,993	1,080	-	2.9	29	348	11.8	0.5	3.6	218
Subtotal Retrofit Energy Efficiency	**988**	**68**	**29**	**97**	**56**	**154**	**63%**	**37%**	**3,455**	**3,455**	**118**	**-**	**3**	**297**	**142**	**456**	**48**	**69**	**32,468**	**1,095**	**-**	**3.0**	**56**	**574**	**10.2**	**0.5**	**2.9**	**285**
FS E* Furnace Upgrade	600	180	41	221	180	401	55%	45%	-31,920	-31,920	9,000	-	FS	(3,124)	12,668	(4,740)	(495)	6,174	(335,966)	97,448	-	FS	5,416	6,174	1.1	1.4	3.6	9,143
FS EnerChoice Fireplace	400	80	52	132	-	132	100%	0%	-6,320	-6,320	1,111	-	FS	(547)	1,403	(842)	(89)	684	(59,886)	10,791	-	FS	931	684	0.7	1.2	2.1	725
FS Gas Cooking Range	675	101	18	119	-	119	100%	0%	(5,265)	(5,265)	581	-	FS	(515)	818	(782)	(82)	399	(55,415)	6,294	-	FS	864	399	0.5	1.2	1.3	184
FS Gas Clothes Dryer	675	101	18	119	-	119	100%	0%	(2,565)	(2,565)	525	-	FS	(200)	604	(311)	(33)	294	(22,211)	4,648	-	FS	345	294	0.9	1.0	1.9	285
Subtotal Retrofit Fuel Substitution	**2,350**	**463**	**128**	**591**	**180**	**771**	**77%**	**23%**	**(46,070)**	**(46,070)**	**11,217**	**-**	**FS**	**(4,387)**	**15,494**	**(6,675)**	**(699)**	**7,551**	**(473,479)**	**119,181**	**-**	**FS**	**7,554**	**7,551**	**1.0**	**1.3**	**3.0**	**10,336**
2010 Subtotal Energy Efficiency	**2,495**	**257**	**72**	**329**	**77**	**407**	**81%**	**19%**	**11,934**	**11,934**	**206**	**-**	**3**	**1,019**	**249**	**1,571**	**166**	**121**	**111,776**	**1,913**	**-**	**3.1**	**77**	**1,858**	**24.0**	**0.5**	**3.1**	**861**
2010 Subtotal Fuel Substitution	**3,512**	**731**	**203**	**934**	**157**	**1,090**	**86%**	**14%**	**(61,558)**	**(61,558)**	**13,588**	**-**	**FS**	**(5,452)**	**17,928**	**(8,349)**	**(878)**	**8,738**	**(593,125)**	**137,905**	**-**	**FS**	**9,385**	**8,738**	**0.9**	**1.3**	**2.7**	**11,386**
2010 Total Residential	**6,007**	**988**	**275**	**1,263**	**234**	**1,497**	**84%**	**16%**	**(49,624)**	**(49,624)**	**13,794**	**-**	**-**	**(4,432)**	**18,176**	**(6,779)**	**(713)**	**8,859**	**(481,349)**	**139,818**	**-**	**(3.5)**	**234**	**1,368**	**5.8**	**0.8**	**9.2**	**12,247**
2008 - 2010 (NPV 2007)																												
RESIDENTIAL:																												
New Construction																												
EE EnerChoice Fireplace	1,454	291	54	345	-	345	100%	0%	12,069	12,069	36	-	3	1,203	53	1,855	189	26	131,970	407	-	3.5	-	2,070	N/A	0.5	3.6	911
EE E* Hot Water Saving Appliances	1,122	34	73	107	34	142	76%	24%	2,523	2,523	105	-	4	230	145	359	37	70	25,566	1,112	-	2.1	34	466	13.6	0.5	2.6	233
Subtotal New Constuction Energy Efficiency	**2,576**	**325**	**127**	**452**	**34**	**487**	**93%**	**7%**	**14,592**	**14,592**	**141**	**-**	**3**	**1,433**	**198**	**2,214**	**226**	**96**	**157,537**	**1,520**	**-**	**3.2**	**34**	**2,536**	**73.8**	**0.5**	**3.4**	**1,144**
FS Natural Gas DHW	1,339	469	138	607	-	607	100%	0%	(25,176)	(25,176)	3,831	-	FS	(1,844)	4,205	(2,915)	(299)	2,049	(208,761)	32,345	-	FS	3,213	2,049	0.6	1.2	1.7	1,754
FS Gas Cooking Range	233	12	33	45	(12)	33	135%	-35%	(1,768)	(1,768)	196	-	FS	(200)	321	(305)	(31)	156	(21,598)	2,469	-	FS	336	168	0.5	1.2	1.4	87
FS Gas Clothes Dryer	464	23	9	33	(23)	9	350%	-250%	(1,746)	(1,746)	359	-	FS	(198)	586	(301)	(31)	286	(21,331)	4,507	-	FS	332	309	0.9	1.3	2.8	379
Subtotal New Construction Fuel Substitution	**2,036**	**504**	**181**	**684**	**(35)**	**649**	**105%**	**-5%**	**-28,689**	**-28,689**	**4,386**	**-**	**FS**	**(2,242)**	**5,112**	**(3,521)**	**(360)**	**2,491**	**(251,690)**	**39,321**	**-**	**FS**	**3,881**	**2,526**	**0.7**	**1.2**	**1.8**	**2,221**
Retrofit																												
EE E* Furnace Upgrade	156	47	3	50	47	97	52%	48%	1,607	1,607	-	-	3	181	-	275	28	-	19,514	-	-	3.6	47	303	6.5	0.6	1.9	84
EE EnerChoice Fireplace	104	21	2	23	-	23	100%	0%	863	863	3	-	2	86	4	133	14	2	9,438	29	-	3.8	-	148	N/A	0.6	3.9	67
EE E* Hot Water Saving Appliances	1,431	50	66	117	50	167	70%	30%	3,473	3,473	202	-	3	321	280	499	51	136	35,531	2,154	-	2.7	50	686	13.6	0.5	3.6	434
Subtotal Retrofit Energy Efficiency	**1,691**	**118**	**71**	**189**	**97**	**287**	**66%**	**34%**	**5,943**	**5,943**	**205**	**-**	**3**	**588**	**284**	**907**	**92**	**138**	**64,482**	**2,183**	**-**	**3.1**	**97**	**1,137**	**11.7**	**0.5**	**3.0**	**585**
FS E* Furnace Upgrade	1,593	478	203	681	478	1,159	59%	41%	(84,726)	(84,726)	23,889	-	FS	(9,342)	38,005	(14,220)	(1,417)	18,523	(1,007,899)	292,345	-	FS	16,115	18,523	1.1	1.4	3.6	27,504
FS EnerChoice Fireplace	722	144	142	286	-	286	100%	0%	(11,401)	(11,401)	2,004	-	FS	(1,134)	2,914	(1,749)	(178)	1,420	(124,412)	22,419	-	FS	1,927	1,420	0.7	1.2	2.1	1,494
FS Gas Cooking Range	1,170	175	38	214	-	214	100%	0%	(4,445)	(4,445)	910	-	FS	(399)	1,208	(623)	(64)	589	(44,423)	9,295	-	FS	687	589	0.9	1.0	2.0	595
FS Gas Clothes Dryer	1,170	175	38	214	-	214	100%	0%	(9,125)	(9,125)	1,007	-	FS	(1,028)	1,636	(1,564)	(158)	798	(110,831)	12,587	-	FS	1,722	798	0.5	1.3	1.3	395
Subtotal Retrofit Fuel Substitution	**4,654**	**973**	**422**	**1,395**	**478**	**1,873**	**74%**	**26%**	**(109,697)**	**(109,697)**	**27,811**	**-**	**FS**	**(11,903)**	**43,764**	**(18,156)**	**(1,817)**	**21,330**	**(1,287,565)**	**336,647**	**-**	**FS**	**20,451**	**21,330**	**1.0**	**1.4**	**3.2**	**29,988**
2008-2010 Subtotal Energy Efficiency	**4,266**	**443**	**198**	**642**	**132**	**773**	**83%**	**17%**	**20,535**	**20,535**	**346**	**-**	**3**	**2,021**	**481**	**3,120**	**318**	**235**	**222,019**	**3,703**	**-**	**3.1**	**132**	**3,673**	**27.9**	**0.5**	**3.2**	**1,729**
2008-2010 Subtotal Fuel Substitution	**6,690**	**1,477**	**602**	**2,079**	**443**	**2,522**	**82%**	**18%**	**(138,387)**	**(138,387)**	**32,197**	**-**	**FS**	**(14,145)**	**48,876**	**(21,677)**	**(2,177)**	**23,821**	**(1,539,255)**	**375,967**	**-**	**FS**	**24,297**	**23,821**	**0.98**	**1.3**	**2.9**	**32,209**
2008-2010 Total Residential	**10,956**	**1,920**	**801**	**2,721**	**575**	**3,295**	**83%**	**17%**	**(117,852)**	**(117,852)**	**32,543**	**-**	**-**	**(12,124)**	**49,357**	**(18,556)**	**(1,859)**	**24,056**	**(1,317,236)**	**379,671**	**-**	**(4.5)**	**575**	**3,641**	**6.3**	**0.8**	**11.3**	**33,938**

TERASEN GAS VANCOUVER ISLAND

		PROGRAM												ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
		COSTS ($000)							SAVINGS (GJ)			LIFE	Impact		Levelized Cost	Utility Benefits		Participant Benefits (Costs)			Program Net Savings				Participant					
		Utility										Years	Energy	Capacity	($/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
	Participants	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net-to-Gross	Net		MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
	Label	B	C	D	E	F	G	H	Input (program)	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Source Sheet or Calculation	Program	Program	B+C	Program	D+E	D/F	E/F	Program	Program	IxJ	Program	Program	Program	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2008																														
RESIDENTIAL:																														
New Construction																														
EE EnerChoice Fireplace	280	56	28	84	-	84	100%	0%	2,324	100%	2,324	15	7	-	4	202	9	310	29	4	22,021	68	-	2.4	-	343	N/A	0.5	2.5	127
EE E* Clothes Washer	42	2	35	37	2	39	95%	5%	119	100%	119	14	13	-	35	10	15	15	1	7	1,079	117	-	0.3	2	24	11.4	0.2	0.6	(14)
EE E* Dishwasher	200	5	4	9	5	14	64%	36%	416	100%	416	13	7	-	2	33	8	51	5	4	3,602	59	-	3.6	5	59	11.8	0.5	2.9	26
FS Natural Gas DHW	336	118	73	191	-	191	100%	0%	-6,317	100%	-6,317	10	961	-	FS	(409)	920	(638)	(59)	448	(45,667)	7,075	-	FS	697	448	0.6	1.1	1.5	319
FS Gas Cooking Range	39	2	17	19	(2)	17	111%	-11%	-296	100%	-296	18	33	-	FS	(29)	46	(44)	(4)	23	(3,120)	357	-	FS	48	25	0.5	0.9	1.0	0
FS Gas Clothes Dryer	77	4	2	5	(4)	2	350%	-250%	-290	100%	-290	18	59	-	FS	(28)	84	(43)	(4)	41	(3,047)	644	-	FS	47	45	0.9	1.3	2.8	54
Retrofit																														
EE E* Furnace Upgrade	30	9	1	10	9	19	52%	48%	309	100%	309	18	-	-	3	30	N/A	46	4	N/A	3,252	-	-	3.1	9	50	5.6	0.5	1.6	12
EE EnerChoice Fireplace	20	4	0	4	-	4	100%	0%	166	100%	166	15	1	-	3	14	1	22	2	0	1,573	5	-	3.3	-	25	N/A	0.5	3.4	11
EE E * Dishwasher	175	4	27	31	4	36	88%	12%	368	100%	368	13	5	-	10	29	6	45	4	3	3,182	43	-	0.9	4	52	11.8	0.4	1.0	(1)
EE E* Clothes Washer	113	6	2	8	6	14	58%	42%	328	100%	328	14	34	-	3	27	42	42	4	20	2,976	320	-	3.4	6	66	11.7	0.5	5.1	55
FS E* Furnace Upgrade	600	180	99	279	180	459	61%	39%	-31,920	100%	-31,920	18	9,000	-	FS	(3,118)	12,668	(4,740)	(447)	6,174	(335,966)	97,448	-	FS	5,367	6,174	1.2	1.4	3.5	9,092
FS EnerChoice Fireplace	150	30	59	89	-	89	100%	0%	-2,370	100%	-2,370	15	417	-	FS	(206)	526	(316)	(30)	256	(22,457)	4,047	-	FS	345	256	0.7	1.1	1.8	231
FS Gas Cooking Range	225	34	13	47	-	47	100%	0%	-1,755	100%	-1,755	18	194	-	FS	(171)	273	(261)	(25)	133	(18,472)	2,098	-	FS	285	133	0.5	1.2	1.3	55
FS Gas Clothes Dryer	225	34	13	47	-	47	100%	0%	-855	100%	-855	13	175	-	FS	(67)	201	(104)	(10)	98	(7,404)	1,549	-	FS	114	98	0.9	0.9	1.8	88
2008																														
Total Residential	2,512	487	372	859	200	1,060	81%	19%	-39,774		-39,774		10,905	-	FS	-3,684	14,798	-5,615	-529	7,212	(398,446)	113,830	-	FS	6,344	7,212	1.1	1.2	3.1	10,054
2009																														
RESIDENTIAL:																														
New Construction																														
EE EnerChoice Fireplace	559	112	14	125	-	125	100%	0%	4,640	100%	4,640	15	14	-	3	399	18	618	62	9	43,964	136	-	3.2	-	689	N/A	0.5	3.3	291
FS Natural Gas DHW	500	175	24	199	-	199	100%	0%	-9,400	100%	-9,400	10	1,431	-	FS	(597)	1,369	(949)	(96)	667	(67,956)	10,529	-	FS	1,045	667	0.6	1.2	1.7	573
EE E* Clothes Washer	84	4	12	17	4	21	80%	20%	238	100%	238	14	25	-	8	19	30	30	3	15	2,159	234	-	1.2	4	48	11.5	0.4	2.4	29
EE E* Dishwasher	300	8	6	14	8	21	64%	36%	624	100%	624	13	10	-	2	48	12	76	8	6	5,403	89	-	3.6	8	89	11.9	0.5	2.8	39
FS Gas Cooking Range	77	4	9	13	(4)	9	142%	-42%	-585	100%	-585	18	65	-	FS	(57)	92	(87)	(9)	45	(6,159)	704	-	FS	96	48	0.5	1.2	1.4	25
FS Gas Clothes Dryer	154	8	3	11	(8)	3	350%	-250%	-579	100%	-579	18	119	-	FS	(56)	167	(86)	(9)	82	(6,095)	1,288	-	FS	95	89	0.9	1.3	2.8	108
Retrofit																														
FS E* Furnace Upgrade	600	180	86	266	$ 180.00	446	60%	40%	-31,920	100%	-31,920	18	9,000	-	FS	(3,100)	12,668	(4,740)	(474)	6,174	(335,966)	97,448	-	FS	5,394	6,174	1.1	1.4	3.6	9,122
EE E* Furnace Upgrade	60	18	1	19	$ 18.00	37	52%	48%	618	100%	618	18	-	-	3	60	N/A	92	9	N/A	6,505	-	-	3.1	18	101	5.6	0.5	1.6	23
FS EnerChoice Fireplace	281	56	49	105	$ -	105	100%	0%	-4,440	100%	-4,440	15	781	-	FS	(382)	986	(591)	(59)	480	(42,070)	7,581	-	FS	651	480	0.7	1.2	2.0	499
EE EnerChoice Fireplace	40	8	1	9	$ -	9	100%	0%	332	100%	332	15	1	-	3	29	1	44	4	1	3,146	10	-	3.2	-	49	N/A	0.5	3.4	21
EE E * Dishwasher	300	8	15	23	$ 7.50	30	75%	25%	630	100%	630	13	8	-	4	49	10	76	8	5	5,455	74	-	2.1	8	89	11.8	0.5	1.9	28
EE E* Clothes Washer	225	11	5	16	$ 11.25	27	58%	42%	653	100%	653	14	69	-	3	53	83	83	8	40	5,925	637	-	3.4	11	132	11.7	0.5	5.0	109
FS Gas Cooking Range	450	68	13	81	$ -	81	100%	0%	-3,510	100%	-3,510	18	388	-	FS	(341)	545	(521)	(52)	266	(36,944)	4,196	-	FS	573	266	0.5	1.2	1.3	124
FS Gas Clothes Dryer	450	68	13	81	$ -	81	100%	0%	-1,710	100%	-1,710	13	350	-	FS	(132)	403	(208)	(21)	196	(14,808)	3,098	-	FS	229	196	0.9	1.0	1.9	190
2009																														
Total Residential	4,080	726	252	978	217	1,195	82%	18%	-44,410		-44,410		12,260	-	FS	-4,008	16,383	-6,162	-618	7,985	(437,441)	126,023	-	FS	6,997	7,985	1.1	1.2	3.1	11,181
2010																														
RESIDENTIAL:																														
New Construction																														
EE EnerChoice Fireplace	839	168	19	187	-	187	100%	0%	6,964	100%	6,964	15	21	-	3	602	26	928	98	13	65,985	204	-	3.2	-	1,038	N/A	0.5	3.4	442
FS Natural Gas DHW	700	245	58	303	-	303	100%	0%	-13,160	100%	-13,160	10	2,003	-	FS	(837)	1,916	(1,328)	(143)	934	(95,139)	14,741	-	FS	1,472	934	0.6	1.2	1.7	776
EE E* Clothes Washer	168	8	14	22	8	31	73%	27%	475	100%	475	14	50	-	5	39	61	61	6	30	4,317	467	-	1.7	8	97	11.5	0.5	3.2	69
EE E* Dishwasher	500	13	10	23	13	35	64%	36%	1,040	100%	1,040	13	17	-	2	81	19	126	13	9	9,006	148	-	3.6	13	149	11.9	0.5	2.9	65
FS Gas Cooking Range	154	8	11	18	(8)	11	172%	-72%	-1,170	100%	-1,170	18	130	-	FS	(115)	183	(174)	(18)	89	(12,319)	1,408	-	FS	192	97	0.5	1.3	1.5	58
FS Gas Clothes Dryer	308	15	6	22	(15)	6	350%	-250%	-1,158	100%	-1,158	18	238	-	FS	(113)	335	(172)	(18)	163	(12,189)	2,575	-	FS	190	179	0.9	1.3	2.8	215
Retrofit																														
FS E* Furnace Upgrade	600	180	41	221	180	401	55%	45%	-31,920	100%	-31,920	18	9,000	-	FS	(3,124)	12,668	(4,740)	(495)	6,174	(335,966)	97,448	-	FS	5,416	6,174	1.1	1.4	3.6	9,143
EE E* Furnace Upgrade	90	27	2	29	27	56	52%	48%	927	100%	927	18	-	-	3	91	N/A	138	14	N/A	9,757	-	-	3.2	27	152	5.6	0.5	1.6	35
FS EnerChoice Fireplace	400	80	52	132	-	132	100%	0%	-6,320	100%	-6,320	15	1,111	-	FS	(547)	1,403	(842)	(89)	684	(59,886)	10,791	-	FS	931	684	0.7	1.2	2.1	725
EE EnerChoice Fireplace	60	12	1	13	-	13	100%	0%	498	100%	498	15	2	-	3	43	2	66	7	1	4,719	15	-	3.3	-	74	N/A	0.5	3.4	32
EE E * Dishwasher	500	13	19	32	13	44	72%	28%	1,050	100%	1,050	13	14	-	3	82	16	127	14	8	9,092	123	-	2.6	13	149	11.9	0.5	2.2	54
EE E* Clothes Washer	338	17	7	24	17	41	58%	42%	980	100%	980	14	103	-	3	81	124	125	13	61	8,900	957	-	3.4	17	199	11.8	0.5	5.1	165
FS Gas Cooking Range	675	101	18	119	-	119	100%	0%	-5,265	100%	-5,265	18	581	-	FS	(515)	818	(782)	(82)	399	(55,415)	6,294	-	FS	864	399	0.5	1.2	1.3	184
FS Gas Clothes Dryer	675	101	18	119	-	119	100%	0%	-2,565	100%	-2,565	13	525	-	FS	(200)	604	(311)	(33)	294	(22,211)	4,648	-	FS	345	294	0.9	1.0	1.9	285
2010																														
Total Residential	6,007	988	275	1,263	234	1,497	84%	16%	-49,624		-49,624		13,794	-	FS	(4,432)	18,176	(6,779)	-713	8,859	(481,349)	139,818	-	FS	7,725	8,859	1.1	1.2	3.1	12,247

SHEET LABELS

Residential

New Construction		
	EE EnerChoice Fireplace	**FP**
	FS Natural Gas DHW	**NG DHW**
	EE E* Clothes Washer	**E Clothes**
	EE E* Dishwasher	**E Dish**
	FS Gas Cooking Range	**LB Range**
	FS Gas Clothes Dryer	**LB Dryer**
Retrofit		
	FS E* Furnace Upgrade	**Retrofit Furnace**
	EE E* Furnace Upgrade	
	FS EnerChoice Fireplace	**Retrofit FP**
	EE EnerChoice Fireplace	
	EE E * Dishwasher	**Retrofit E Dish**
	EE E* Clothes Washer	**Retrofit E Clothes**
	FS Gas Clothes Dryer	
	FS Gas Cooking Range	

2008

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for EE EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	8.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%			Net-to-Gross
Alternate Energy Impact	0.09	GJ		25	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	15	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			3000	3000	3000	Information Only
Participants	1,454	1,678	280	559	839	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	12,069	13,927	2,324	4,640	6,964	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	12,069	13,927	2,324	4,640	6,964	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	36,352	41,950	7,000	13,975	20,975	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ 1,202,619	$ 1,202,619	$ 201,597	$ 398,682	$ 602,340	
Utility Program Costs						
DSM Incentives		$ 335,600	$ 56,000	$ 111,800	$ 167,800	
Administration		$ 60,540	$ 27,590	$ 13,680	$ 19,270	
Subtotal	$ 344,848	$ 396,140	$ 83,590	$ 125,480	$ 187,070	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 52,966	$ 8,838	$ 17,645	$ 26,483	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 52,966	$ 52,966	$ 8,838	$ 17,645	$ 26,483	
Net Present Benefit (Cost)	$ 910,737	$ 859,445	$126,845	$290,847	$441,753	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	3.6		2.5	3.3	3.4	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 3.02		$ 3.80	$ 2.85	$ 2.84	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for EE E* Clothes Washer

PER MEASURE

Total Cost	$	100
Incentive	$	50
Participant	$	50

Annual Impact Per Measure

Energy Savings per installation	2.83	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	1.0768	GJ	299	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	14	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			800	800	800	Information Only
Participants	253	294	42	84	168	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	717	832	119	238	475	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	717	832	119	238	475	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	75,752	87,939	12,563	25,125	50,251	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$82.51	$81.85	$82.39	
Energy Purchases	$ 68,435	$ 68,435	$ 9,807	$ 19,458	$ 39,170	
Utility Program Costs						
DSM Incentives		$ 14,700	$ 2,100	$ 4,200	$ 8,400	
Administration		$ 61,547	$ 35,173	$ 12,347	$ 14,027	
Subtotal	$ 68,288	$ 76,247	$ 37,273	$ 16,547	$ 22,427	
Participants' Net Costs						
Incremental Cost		$ 14,700	$ 2,100	$ 4,200	$ 8,400	
Subtotal	$ 12,663	$ 14,700	$ 2,100	$ 4,200	$ 8,400	
Alternate Savings - Net						
Energy (Purchases)		$ 106,261	$ 15,180	$ 30,360	$ 60,720	$1.208 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 106,261	$ 106,261	$ 15,180	$ 30,360	$ 60,720	
Net Present Benefit (Cost)	$ 93,745	$ 83,749	($14,386)	$29,071	$69,063	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.2**		**0.6**	**2.4**	**3.2**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 12.44**		**$ 36.48**	**$ 9.61**	**$ 7.14**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for EE E* Dishwasher

PER MEASURE

Total Cost	$	50
Incentive	$	25
Participant	$	25

Annual Impact Per Measure

Energy Savings per installation	2.08	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%			Net-to-Gross
Alternate Energy Impact	0.12	GJ		33	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	13	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			1500	1500	1500	Information Only
Participants	868	1,000	200	300	500	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,806	2,080	416	624	1,040	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	1,806	2,080	416	624	1,040	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	28,948	33,333	6,667	10,000	16,667	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$78.30	$77.35	$78.05	
Energy Purchases	$ 162,013	$ 162,013	$ 32,574	$ 48,265	$ 81,173	
Utility Program Costs						
DSM Incentives		$ 25,000	$ 5,000	$ 7,500	$ 12,500	
Administration		$ 20,000	$ 4,000	$ 6,000	$ 10,000	
Subtotal	$ 39,079	$ 45,000	$ 9,000	$ 13,500	$ 22,500	
Participants' Net Costs						
Incremental Cost		$ 25,000	$ 5,000	$ 7,500	$ 12,500	
Subtotal	$ 21,711	$ 25,000	$ 5,000	$ 7,500	$ 12,500	
Alternate Savings - Net						
Energy (Purchases)		$ 38,362	$ 7,672	$ 11,508	$ 19,181	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 38,362	$ 38,362	$ 7,672	$ 11,508	$ 19,181	
Net Present Benefit (Cost)	$ 139,584	$ 130,374	$26,247	$38,774	$65,354	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.3**		**2.9**	**2.8**	**2.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 3.89**		**$ 3.89**	**$ 3.89**	**$ 3.89**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for FS Natural Gas DHW

PER MEASURE

Total Cost	$	350
Incentive	$	350
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	-18.8	GJ		Average Annnual Energy Savings per
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	10.3	GJ	2,861	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	10	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010
Market Size			1700	1700	1700
Participants	1,339	1,536	336	500	700
Impact					
Gross Energy Savings (GJ)	-25,176	-28,877	-6,317	-9,400	-13,160
Net Energy Savings (GJ)	-25,176	-28,877	-6,317	-9,400	-13,160
Alternate Energy Impact (Increase) (kWh)	3,831,404	4,394,667	961,333	1,430,556	2,002,778
ernate Capacity Impact (Increase) (kW/a)	-	-			

Cost Benefit Summary

	2007 NPV	$ Total	2008	2009	2010
Avoided Revenue Requirements					
PV $ per GJ			$64.83	$63.53	$63.61
Energy Purchases	$ (1,843,754)	$ (1,843,754)	$ (409,499)	$ (597,175)	$ (837,081)
Utility Program Costs					
DSM Incentives		$ 537,600	$ 117,600	$ 175,000	$ 245,000
Administration		$ 155,052	$ 73,386	$ 23,833	$ 57,833
Subtotal	$ 606,780	$ 692,652	$ 190,986	$ 198,833	$ 302,833
Participants' Net Costs					
Incremental Cost		$ -	$ -	$ -	$ -
Subtotal	$ -	$ -	$ -	$ -	$ -
Alternate Savings - Net					
Energy (Purchases)		$ 4,204,867	$ 919,815	$ 1,368,772	$ 1,916,281
Capacity (Purchases)		$ -	$ -	$ -	$ -
Subtotal	$ 4,204,867	$ 4,204,867	$ 919,815	$ 1,368,772	$ 1,916,281
Net Present Benefit (Cost)	$ 1,754,333	$ 1,668,461	$319,330	$572,764	$776,367
Benefit/Cost Ratio	3.9		2.7	3.9	3.6
Levelized Cost per GJ (Lifetime)	$ -		$ -	$ -	$ -

r Measure

Explanatory Notes

Information Only

Estimated Participatation

Extension of Unit Savings x No. of Upgrades

Gross Energy Savings less Free Riders

Other Utility Billed energy impact

Other Utility Billed capacity impact

$0.957 PV $ per kWh

PV$ per kW/a

Avoided Revenue Requirement less Utility + Participant Costs

Less planning, evaluation, research

Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for FS Gas Cooking Range

PER MEASURE

Total Cost	$	-
Incentive	$	50
Participant	$	(50)

Annual Impact Per Measure

Energy Savings per installation	-7.6	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	3.04	GJ	844	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	18	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			200	200	200	Information Only
Participants	233	270	39	77	154	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-1,768	-2,052	-296	-585	-1,170	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-1,768	-2,052	-296	-585	-1,170	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	196,437	228,000	32,933	65,022	130,044	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ (200,345)	$ (200,345)	$ (28,951)	$ (56,830)	$ (114,563)	
Utility Program Costs						
DSM Incentives		$ 13,500	$ 1,950	$ 3,850	$ 7,700	
Administration		$ 37,057	$ 17,103	$ 9,207	$ 10,747	
Subtotal	$ 44,771	$ 50,557	$ 19,053	$ 13,057	$ 18,447	
Participants' Net Costs						
Incremental Cost		$ (13,500)	$ (1,950)	$ (3,850)	$ (7,700)	
Subtotal	$ (11,631)	$ (13,500)	$ (1,950)	$ (3,850)	$ (7,700)	
Alternate Savings - Net						
Energy (Purchases)		$ 320,930	$ 46,357	$ 91,525	$ 183,049	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 320,930	$ 320,930	$ 46,357	$ 91,525	$ 183,049	
Net Present Benefit (Cost)	$ 87,446	$ 83,529	$302	$25,487	$57,739	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	3.6		1.0	3.8	6.4	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ -		$ -	$ -	$ -	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
NEW

Measure Data for FS Gas Clothes Dryer

PER MEASURE

Total Cost	$	-
Incentive	$	50
Participant	$	(50)

Annual Impact Per Measure

Energy Savings per installation	-3.76	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	2.78	GJ	772	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	18	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Market Size			800	800	800	Information Only
Participants	464	539	77	154	308	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-1,746	-2,027	-290	-579	-1,158	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-1,746	-2,027	-290	-579	-1,158	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	358,547	416,228	59,461	118,922	237,844	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ (197,868)	$ (197,868)	$ (28,279)	$ (56,232)	$ (113,357)	
Utility Program Costs						
DSM Incentives		$ 26,950	$ 3,850	$ 7,700	$ 15,400	
Administration		$ 10,780	$ 1,540	$ 3,080	$ 6,160	
Subtotal	$ 32,501	$ 37,730	$ 5,390	$ 10,780	$ 21,560	
Participants' Net Costs						
Incremental Cost		$ (26,950)	$ (3,850)	$ (7,700)	$ (15,400)	
Subtotal	$ (23,215)	$ (26,950)	$ (3,850)	$ (7,700)	$ (15,400)	
Alternate Savings - Net						
Energy (Purchases)		$ 585,877	$ 83,697	$ 167,394	$ 334,787	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 585,877	$ 585,877	$ 83,697	$ 167,394	$ 334,787	
Net Present Benefit (Cost)	$ 378,723	$ 377,229	$53,878	$108,082	$215,270	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**41.8**		**36.0**	**36.1**	**35.9**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for EE E* Furnace Upgrade

PER MEASURE

Total Cost	$	600
Incentive	$	300
Participant	$	300

Annual Impact Per Measure

Energy Savings per installation	10.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%			Net-to-Gross
Alternate Energy Impact	0.0	GJ		0	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	156	180	30	60	90	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,607	1,854	309	618	927	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	1,607	1,854	309	618	927	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	0	0	0	0	0	Other Utility Billed energy impact
lternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ 180,936	$ 180,936	$ 30,182	$ 60,016	$ 90,738	
Utility Program Costs						
DSM Incentives		$ 54,000	$ 9,000	$ 18,000	$ 27,000	
Administration		$ 3,600	$ 600	$ 1,200	$ 1,800	
Subtotal	$ 49,913	$ 57,600	$ 9,600	$ 19,200	$ 28,800	
Participants' Net Costs						
Incremental Cost		$ 54,000	$ 9,000	$ 18,000	$ 27,000	
Subtotal	$ 46,794	$ 54,000	$ 9,000	$ 18,000	$ 27,000	
Alternate Savings - Net						
Energy (Purchases)		$ -	$ -	$ -	$ -	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ -	$ -	$ -	$ -	$ -	
Net Present Benefit (Cost)	$ 84,229	$ 69,336	$11,582	$22,816	$34,938	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**1.9**		**1.6**	**1.6**	**1.6**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 5.72**		**$ 5.72**	**$ 5.72**	**$ 5.72**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for EE EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	8.3	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%			Net-to-Gross
Alternate Energy Impact	0.09	GJ		25	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	15	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	104	120	20	40	60	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	863	996	166	332	498	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	863	996	166	332	498	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	2,600	3,000	500	1,000	1,500	Other Utility Billed energy impact
lternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ 86,004	$ 86,004	$ 14,400	$ 28,528	$ 43,076	
Utility Program Costs						
DSM Incentives		$ 24,000	$ 4,000	$ 8,000	$ 12,000	
Administration		$ 2,400	$ 400	$ 800	$ 1,200	
Subtotal	$ 22,877	$ 26,400	$ 4,400	$ 8,800	$ 13,200	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 3,788	$ 631	$ 1,263	$ 1,894	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 3,788	$ 3,788	$ 631	$ 1,263	$ 1,894	
Net Present Benefit (Cost)	$ 66,915	$ 63,391	$10,631	$20,991	$31,769	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.9**		**3.4**	**3.4**	**3.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 2.80**		**$ 2.80**	**$ 2.80**	**$ 2.80**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for EE E * Dishwasher

PER MEASURE

Total Cost	$ 50				
Incentive	$ 25				
Participant	$ 25				
Annual Impact Per Measure					
Energy Savings per installation	2.1	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%			Net-to-Gross
Alternate Energy Impact	0.1	GJ		28	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	13	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	845	975	175	300	500	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,774	2,048	368	630	1,050	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	1,774	2,048	368	630	1,050	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	23,470	27,083	4,861	8,333	13,889	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$78.30	$77.35	$78.05	
Energy Purchases	$ 159,459	$ 159,459	$ 28,777	$ 48,729	$ 81,953	
Utility Program Costs						
DSM Incentives		$ 24,375	$ 4,375	$ 7,500	$ 12,500	
Administration		$ 61,167	$ 26,833	$ 15,167	$ 19,167	
Subtotal	$ 75,670	$ 85,542	$ 31,208	$ 22,667	$ 31,667	
Participants' Net Costs						
Incremental Cost		$ 24,375	$ 4,375	$ 7,500	$ 12,500	
Subtotal	$ 21,123	$ 24,375	$ 4,375	$ 7,500	$ 12,500	
Alternate Savings - Net						
Energy (Purchases)		$ 31,169	$ 5,594	$ 9,590	$ 15,984	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 31,169	$ 31,169	$ 5,594	$ 9,590	$ 15,984	
Net Present Benefit (Cost)	$ 93,835	$ 80,711	($1,212)	$28,153	$53,770	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	2.0		1.0	1.9	2.2	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	$ 6.30		$ 11.18	$ 5.53	$ 4.86	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for EE E* Clothes Washer

PER MEASURE

Total Cost	$	100
Incentive	$	50
Participant	$	50

Annual Impact Per Measure

Energy Savings per installation	2.9	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	1.0968	GJ	305	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	14	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	586	676	113	225	338	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	1,699	1,960	328	653	980	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	1,699	1,960	328	653	980	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	178,475	205,955	34,427	68,550	102,977	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$82.51	$81.85	$82.39	
Energy Purchases	$ 161,203	$ 161,203	$ 27,039	$ 53,409	$ 80,756	
Utility Program Costs						
DSM Incentives		$ 33,800	$ 5,650	$ 11,250	$ 16,900	
Administration		$ 13,500	$ 2,250	$ 4,500	$ 6,750	
Subtotal	$ 40,989	$ 47,300	$ 7,900	$ 15,750	$ 23,650	
Participants' Net Costs						
Incremental Cost		$ 33,800	$ 5,650	$ 11,250	$ 16,900	
Subtotal	$ 29,290	$ 33,800	$ 5,650	$ 11,250	$ 16,900	
Alternate Savings - Net						
Energy (Purchases)		$ 248,865	$ 41,600	$ 82,832	$ 124,432	$1.208 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 248,865	$ 248,865	$ 41,600	$ 82,832	$ 124,432	
Net Present Benefit (Cost)	$ 339,790	$ 328,968	$55,089	$109,241	$164,638	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**5.8**		**5.1**	**5.0**	**5.1**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ 4.56**		**$ 4.55**	**$ 4.56**	**$ 4.56**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for FS E* Furnace Upgrade

PER MEASURE

Total Cost	$	600
Incentive	$	300
Participant	$	300

Annual Impact Per Measure

Energy Savings per installation	-53.2	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%			Net-to-Gross
Alternate Energy Impact	54.0	GJ		15,000	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	18	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1,593	1,800	600	600	600	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-84,726	-95,760	-31,920	-31,920	-31,920	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-84,726	-95,760	-31,920	-31,920	-31,920	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	23,888,968	27,000,002	9,000,001	9,000,001	9,000,001	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ (9,342,101)	$ (9,342,101)	$ (3,117,818)	$ (3,099,833)	$ (3,124,450)	
Utility Program Costs						
DSM Incentives		$ 540,000	$ 180,000	$ 180,000	$ 180,000	
Administration		$ 226,000	$ 98,666	$ 86,167	$ 41,167	
Subtotal	$ 680,865	$ 766,000	$ 278,666	$ 266,167	$ 221,167	
Participants' Net Costs						
Incremental Cost		$ 540,000	$ 180,000	$ 180,000	$ 180,000	
Subtotal	$ 477,779	$ 540,000	$ 180,000	$ 180,000	$ 180,000	
Alternate Savings - Net						
Energy (Purchases)		$ 38,004,891	$ 12,668,297	$ 12,668,297	$ 12,668,297	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 38,004,891	$ 38,004,891	$ 12,668,297	$ 12,668,297	$ 12,668,297	
Net Present Benefit (Cost)	$ 27,504,146	$ 27,356,790	$9,091,813	$9,122,297	$9,142,680	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**24.7**		**20.8**	**21.4**	**23.8**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND

RESIDENTIAL

RETROFIT

Measure Data for FS EnerChoice Fireplace

PER MEASURE

Total Cost	$	200
Incentive	$	200
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	-15.8	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%			Net-to-Gross
Alternate Energy Impact	10.0	GJ		2,778	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	15	Years	Estimated lifespan of measure		

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	722	831	150	281	400	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-11,401	-13,130	-2,370	-4,440	-6,320	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-11,401	-13,130	-2,370	-4,440	-6,320	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	2,004,364	2,308,334	416,667	780,556	1,111,111	Other Utility Billed energy impact
ternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$86.75	$85.93	$86.50	
Energy Purchases	$ (1,133,754)	$ (1,133,754)	$ (205,588)	$ (381,505)	$ (546,662)	
Utility Program Costs						
DSM Incentives		$ 166,200	$ 30,000	$ 56,200	$ 80,000	
Administration		$ 160,125	$ 59,166	$ 49,292	$ 51,667	
Subtotal	$ 286,406	$ 326,325	$ 89,166	$ 105,492	$ 131,667	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 2,914,484	$ 526,080	$ 985,524	$ 1,402,881	$1.263 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 2,914,484	$ 2,914,484	$ 526,080	$ 985,524	$ 1,402,881	
Net Present Benefit (Cost)	$ 1,494,324	$ 1,454,405	$231,327	$498,527	$724,552	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**6.2**		**3.6**	**5.7**	**6.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for FS Gas Cooking Range

PER MEASURE

Total Cost	$	150
Incentive	$	150
Participant	$	-

Annual Impact Per Measure

Energy Savings per installation	-7.8	GJ		Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%		Net-to-Gross
Alternate Energy Impact	3.1	GJ	861	kWh
Alternate Capacity Impact		kW/a		
Measure Lifetime	18	Years	Estimated lifespan of measure	

ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1,170	1,350	225	450	675	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-9,125	-10,530	-1,755	-3,510	-5,265	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-9,125	-10,530	-1,755	-3,510	-5,265	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	1,007,362	1,162,500	193,750	387,500	581,250	Other Utility Billed energy impact
lternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$97.68	$97.11	$97.88	
Energy Purchases	$ (1,027,645)	$ (1,027,645)	$ (171,421)	$ (340,865)	$ (515,358)	
Utility Program Costs						
DSM Incentives		$ 202,500	$ 33,750	$ 67,500	$ 101,250	
Administration		$ 43,667	$ 12,833	$ 13,167	$ 17,667	
Subtotal	$ 213,849	$ 246,167	$ 46,583	$ 80,667	$ 118,917	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 1,636,322	$ 272,720	$ 545,441	$ 818,161	$1.408 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 1,636,322	$ 1,636,322	$ 272,720	$ 545,441	$ 818,161	
Net Present Benefit (Cost)	$ 394,828	$ 362,510	$54,716	$123,908	$183,886	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**2.8**		**2.2**	**2.5**	**2.5**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

TERASEN GAS VANCOUVER ISLAND
RESIDENTIAL
RETROFIT

Measure Data for FS Gas Clothes Dryer

PER MEASURE

Total Cost	$ 150				
Incentive	$ 150				
Participant	$ -				

Annual Impact Per Measure

Energy Savings per installation	-3.8	GJ			Average Annnual Energy Savings per Measure
Free Rider Rate / Net-to-Gross	0%	100%			Net-to-Gross
Alternate Energy Impact	2.8	GJ		778	kWh
Alternate Capacity Impact		kW/a			
Measure Lifetime	13	Years	Estimated lifespan of measure		

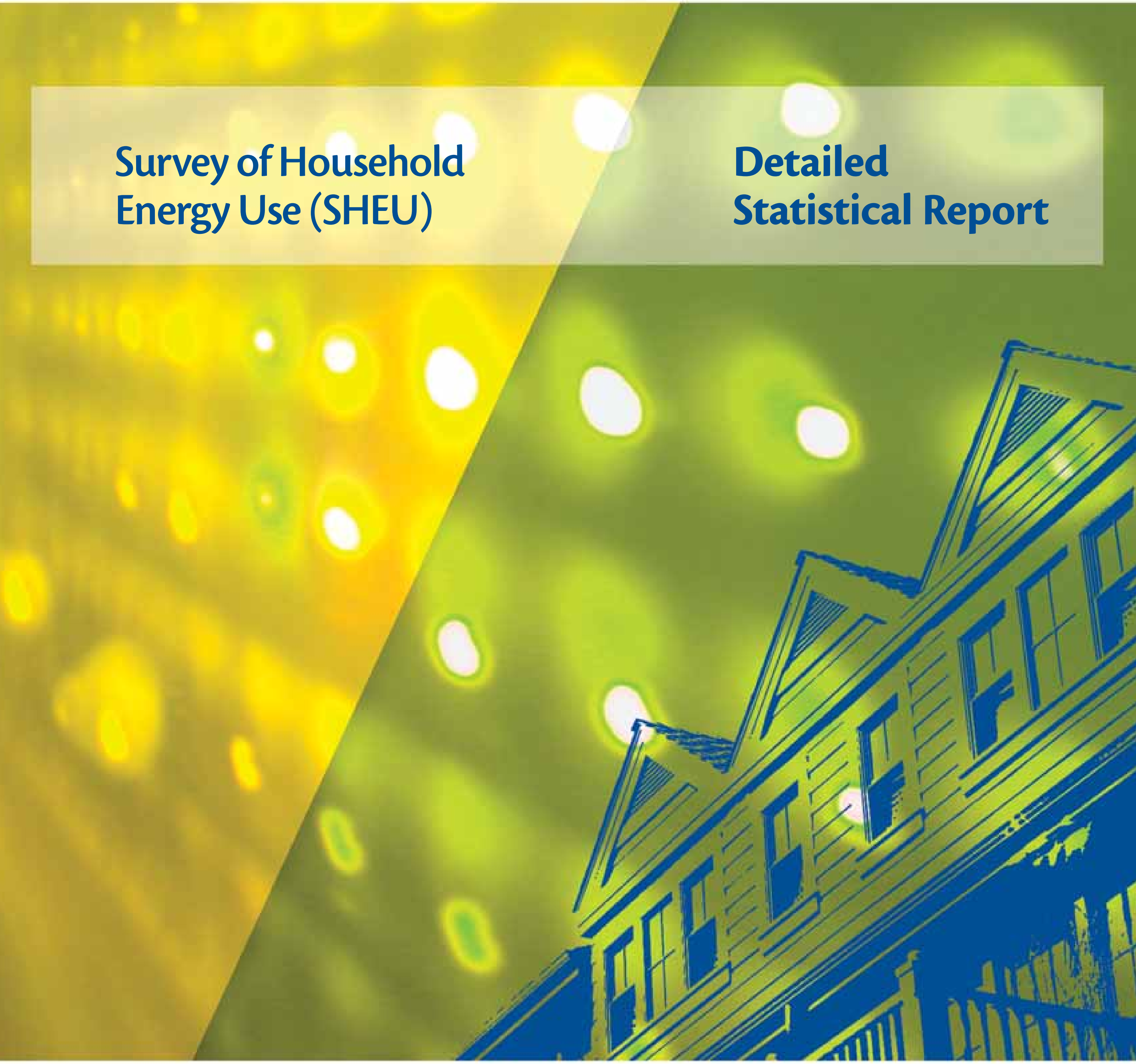
ANNUAL ACTIVITY	2007 NPV	Total	2008	2009	2010	Explanatory Notes
Participants	1,170	1,350	225	450	675	Estimated Participatation
Impact						
Gross Energy Savings (GJ)	-4,445	-5,130	-855	-1,710	-2,565	Extension of Unit Savings x No. of Upgrades
Net Energy Savings (GJ)	-4,445	-5,130	-855	-1,710	-2,565	Gross Energy Savings less Free Riders
Alternate Energy Impact (Increase) (kWh)	909,875	1,050,000	175,000	350,000	525,000	Other Utility Billed energy impact
lternate Capacity Impact (Increase) (kW/a)	-	-				Other Utility Billed capacity impact

Cost Benefit Summary

	2007 NPV	*$ Total*	2008	2009	2010	
Avoided Revenue Requirements						
PV $ per GJ			$78.30	$77.35	$78.05	
Energy Purchases	$ (399,416)	$ (399,416)	$ (66,950)	$ (132,266)	$ (200,201)	
Utility Program Costs						
DSM Incentives		$ 202,500	$ 33,750	$ 67,500	$ 101,250	
Administration		$ 43,667	$ 12,833	$ 13,167	$ 17,667	
Subtotal	$ 213,849	$ 246,167	$ 46,583	$ 80,667	$ 118,917	
Participants' Net Costs						
Incremental Cost		$ -	$ -	$ -	$ -	
Subtotal	$ -	$ -	$ -	$ -	$ -	
Alternate Savings - Net						
Energy (Purchases)		$ 1,208,391	$ 201,399	$ 402,797	$ 604,196	$1.151 PV $ per kWh
Capacity (Purchases)		$ -	$ -	$ -	$ -	PV$ per kW/a
Subtotal	$ 1,208,391	$ 1,208,391	$ 201,399	$ 402,797	$ 604,196	
Net Present Benefit (Cost)	$ 595,126	$ 562,809	$87,866	$189,865	$285,078	Avoided Revenue Requirement less Utility + Participant Costs
Benefit/Cost Ratio	**3.8**		**2.9**	**3.4**	**3.4**	Less planning, evaluation, research
Levelized Cost per GJ (Lifetime)	**$ -**		**$ -**	**$ -**	**$ -**	Informational (for comparison with supply options)

Attachment 67.1

2003



Survey of Household Energy Use (SHEU)

Detailed Statistical Report

Natural Resources Canada
Ressources naturelles Canada

Canada

To obtain additional copies of this or other free publications on energy efficiency, please contact:

Energy Publications
Office of Energy Efficiency
Natural Resources Canada
c/o St. Joseph Communications
Order Processing Unit
1165 Kenaston Street
PO Box 9809 Station T
Ottawa ON K1G 6S1
Tel.: 1 800 387-2000 (toll-free)
Fax: (613) 740-3114
TTY: (613) 996-4397 (teletype for the hearing-impaired)

Cat. No. M144-120/2003E
ISBN 0-662-42491-3

Aussi disponible en français sous le titre :
Enquête 2003 sur l'utilisation de l'énergie par les ménages (EUÉM) : Rapport statistique détaillé

Recycled paper

Foreword

In 2004, Statistics Canada conducted a Survey of Household Energy Use (SHEU) on behalf of the Office of Energy Efficiency (OEE) of Natural Resources Canada (NRCan). The survey ties in directly with the OEE's mandate, which is to strengthen and expand Canada's commitment to energy efficiency in order to help address the challenges of climate change. The results of this survey will also be used to assess the effectiveness of existing energy efficiency programs and to develop new ones.

The survey collected data for the 2003 calendar year reference period, and is referred to in this report as 2003 SHEU. Because the data collection occurred in 2004, Statistics Canada refers to this survey as 2004 SHEU.

The 2003 SHEU builds on the surveys of the same name that were undertaken for 1993 and 1997. Its goal is to gather data on the energy and physical characteristics of private dwellings in Canada and on the household use of energy resources.

This report was prepared by Vincent Fecteau and Glen Ewaschuk, of the Demand Policy and Analysis Division of the OEE. Indrani Hulan and Jean-François Bilodeau supervised the project, and David McNabb provided project leadership.

A summary report presenting the main survey findings is also available. This report is entitled *2003 Survey of Household Energy Use – Summary Report*.

To learn more about this survey and the topics discussed in this document, please contact:

Glen Ewaschuk
Economist
Office of Energy Efficiency
Natural Resources Canada
580 Booth Street, 18th Floor
Ottawa ON K1A 0E4

Fax: (613) 947-0535
E-mail: euc.cec@nrcan.gc.ca

How to interpret the tables

The table shown below is typical of the tables presented in this report. This statistical report contains representative data on the SHEU's target population with regard to number of dwellings, dwelling area, energy consumption and energy intensity.

The target population was composed of all dwellings that were occupied as primary residences in the 10 Canadian provinces[1] and that fit into one of the following categories: single detached house, double/row house, duplex,[2] mobile home or apartment (dwelling in a building with no more than four storeys).

Specifically excluded from the survey's coverage were dwellings not mentioned above, dwellings located in a First Nation community or on a military base, businesses, institutions, demolished dwellings, dwellings under construction, seasonal or secondary residences, and dwellings occupied by someone who works full-time within the Canadian Armed Forces.

As can be seen in the sample table, the estimate for each category is shown in the left column. The number of dwellings is expressed in units; energy consumption, in gigajoules (GJ); heated area, in square metres (m^2); and intensity of each energy source, in gigajoules per square metre (GJ/m^2). Data on the number of dwellings, surface area and energy consumption are rounded to the nearest integer.

Consequently, the sum of the data may differ from the total indicated and may vary slightly from one table to the next.

The letters used in the right column of the statistical tables indicate the degree of sampling error or the coefficient of variation for estimates. The letter "A" indicates that the estimate has a low coefficient of variation and is of acceptable quality. The letter "M" indicates a higher coefficient. Estimates with an "M" are precise enough for certain uses, but their use should be accompanied with a cautionary note. A "U" indicates that the estimate's coefficient of variation exceeds 33.3 percent, or that the size of the sample on which the estimate is based had fewer than 30 units. We did not publish these estimates because they might present too great a sampling error or because they had to be omitted in order to comply with the confidentiality requirements of the *Statistics Act*.

Sample table

Total number of dwellings by province

	Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
Single detached house	7,191,540	A	662,335	A	1,513,497	A	2,724,438	A	1,381,219	A	910,051	A
Double/row house	1,721,416	A	94,150	A	469,193	A	707,777	A	246,848	A	203,449	A
Apartment	2,061,257	A	113,063	A	962,222	A	419,965	A	218,054	A	347,952	A
Mobile home	195,176	A	30,794	M		U		U	56,642	A		U

[1] The territories are not included in the target population.
[2] Duplexes are included in the double/row house category in this report.

Table of Contents

SECTION 1

Characteristics of Households

1.1 Location and characteristics of households

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Region								
Atlantic	662,335	A	94,150	A	113,063	A	30,794	M
Quebec	1,513,497	A	469,193	A	962,222	A		U
Ontario	2,724,438	A	707,777	A	419,965	A		U
Prairies	1,381,219	A	246,848	A	218,054	A	56,642	A
British Columbia	910,051	A	203,449	A	347,952	A		U
Canada	7,191,540	A	1,721,416	A	2,061,257	A	195,176	A
Type of dwelling								
Single detached								
Double/row house								
Apartment								
Mobile home								
Construction period								
Before 1946	1,051,184	A	264,568	A	278,932	A		U
1946–1969	2,101,713	A	382,427	A	622,187	A		U
1970–1979	1,354,912	A	400,346	A	499,387	A	96,481	A
1980–1989	1,270,850	A	329,945	A	376,070	A		U
1990–2003	1,412,882	A	344,130	A	284,682	A		U
Type of population centre								
Urban	5,469,769	A	1,643,598	A	2,014,187	A	99,496	A
Rural	1,721,771	A		U		U	95,681	A
Household income								
Less than $20,000	450,275	A	151,969	A	507,862	A		U
$20,000 to $39,999	1,000,173	A	343,705	A	575,731	A	52,795	M
$40,000 to $59,999	1,100,674	A	333,840	A	279,495	A		U
$60,000 to $79,999	1,006,100	A	269,326	A	169,690	A		U
$80,000 or more	3,184,592	A	571,641	A	463,311	A	65,143	M
Not stated	449,727	A		U		U		U
Occupation mode								
Owner	6,759,357	A	1,047,891	A	329,136	A	176,814	A
Renter	432,183	A	672,295	A	1,732,121	A		U
Not stated		U		U		U		U
Household size								
1 member	1,011,567	A	340,048	A	1,046,801	A	58,026	M
2 members	2,686,354	A	573,132	A	643,458	A	81,610	A
3 members	1,157,218	A	323,390	A	211,695	A		U
4 members or more	2,336,402	A	484,845	A	159,303	A		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 1.1

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
7,191,540 A	662,335 A	1,513,497 A	2,724,438 A	1,381,219 A	910,051 A
1,721,416 A	94,150 A	469,193 A	707,777 A	246,848 A	203,449 A
2,061,257 A	113,063 A	962,222 A	419,965 A	218,054 A	347,952 A
195,176 A	30,794 M	U	U	56,642 A	U
1,594,684 A	189,263 A	470,458 A	552,101 A	261,133 A	121,729 M
3,132,583 A	169,864 A	845,798 A	1,241,774 A	520,653 A	354,494 A
2,351,125 A	220,926 A	668,698 A	692,330 A	455,559 A	313,612 A
2,012,074 A	155,741 A	553,988 A	673,477 A	303,863 A	325,005 A
2,078,923 A	164,548 A	445,302 A	722,350 A	361,555 A	385,169 A
9,227,050 A	554,652 A	2,469,469 A	3,370,283 A	1,529,374 A	1,303,271 A
1,942,339 A	345,690 A	514,775 A	511,748 A	373,389 A	196,738 A
1,130,290 A	135,797 A	367,810 A	305,242 A	147,665 A	173,776 A
1,972,405 A	185,860 A	652,714 A	573,645 A	325,973 A	234,212 A
1,757,429 A	172,531 A	457,338 A	540,717 A	349,785 A	237,058 A
1,452,013 A	82,748 A	329,375 A	575,637 A	260,603 A	203,650 A
4,284,687 A	290,648 A	1,096,672 A	1,629,561 A	689,932 A	577,874 A
572,565 A	32,758 M	80,335 M	257,229 A	128,805 A	73,439 M
8,313,197 A	692,977 A	1,869,283 A	3,157,649 A	1,529,264 A	1,064,024 A
2,854,961 A	207,365 A	1,114,961 A	724,382 A	373,499 A	434,754 A
U	U	U	U	U	U
2,456,442 A	204,153 A	709,427 A	754,443 A	392,832 A	395,587 A
3,984,555 A	347,217 A	1,181,313 A	1,235,263 A	675,483 A	545,279 A
1,715,445 A	157,424 A	421,125 A	606,297 A	314,057 A	216,542 A
3,012,948 A	191,548 A	672,379 A	1,286,028 A	520,391 A	342,602 A

SECTION 2

Thermal Envelope

2.1 Number of storeys and apartments

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Number of storeys in dwelling (excluding basement)								
One storey	3,865,318	A	597,266	A		U	189,785	A
One and a half storeys	772,042	A	90,422	M		U		U
Two storeys	2,060,899	A	893,632	A		U		U
More than two storeys	156,845	A	95,544	M		U		U
Split level or other	336,436	A		U		U		U
Number of storeys in building (excluding indoor parking)								
One storey		U		U		U		U
Two storeys		U		U	418,570	A		U
More than two storeys		U		U	1,605,431	A		U
Number of apartments in building								
2 to 10		U		U	920,015	A		U
11 to 20		U		U	312,423	A		U
21 to 50		U		U	548,803	A		U
51 or more		U		U	258,858	A		U
Don’t know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 2.1

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
4,652,369	A	431,343	A	1,273,260	A	1,259,928	A	1,060,325	A	627,512	A
862,464	A	98,373	A	164,590	A	356,145	A	136,723	A	106,633	A
2,954,532	A	223,414	A	544,778	A	1,480,760	A	357,912	A	347,668	A
252,389	A		U		U	129,187	M		U		U
386,380	A		U		U	236,046	A	70,814	M		U
	U		U		U		U		U		U
418,570	A		U	247,267	A		U		U		U
1,605,431	A	75,784	A	703,009	A	324,588	A	189,609	A	312,441	A
920,015	A		U	627,437	A	200,301	M		U		U
312,423	A		U	145,537	M		U		U		U
548,803	A		U	136,327	M		U		U	169,656	A
258,858	A		U		U		U		U	106,571	M
	U		U		U		U		U		U

2.2 Indoor parking

BY TYPE OF DWELLING

	Single detached	Double/row house	Apartment	Mobile home
Indoor parking in building				
Yes	U	U	463,526 A	U
No	U	U	1,597,730 A	U
Heated indoor parking in building				
Yes	U	U	199,221 A	U
No	U	U	264,305 A	U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 2.2

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
463,526	A		U	174,074	A		U		U	190,330	A
1,597,730	A	109,293	A	788,148	A	365,679	A	176,989	A	157,622	A
199,221	A		U	128,452	M		U		U		U
264,305	A		U		U		U		U	177,252	A

2.3 Basement

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment	Mobile home	
Type of foundation in house							
Basement	5,849,754	A	1,281,779	A	U		U
Crawl space	833,270	A	139,908	A	U		U
Concrete slabs	658,333	A	275,093	A	U		U
Pillars	78,030	M		U	U	55,163	M
Other	116,139	A		U	U		U
No foundation	130,707	M		U	U	61,481	A
Basements / crawl spaces usually heated during the heating season							
Yes	5,085,923	A	1,074,405	A	U		U
No	1,374,719	A	312,876	A	U		U
Don't know		U		U	U		U
Number of insulated outside walls in basements / crawl spaces							
0	1,215,743	A	278,144	A	U		U
1	163,139	A		U	U		U
2	304,386	A	154,362	M	U		U
3	440,380	A	266,324	A	U		U
4	4,007,569	A	491,512	A	U		U
Difficult to answer because shape of house is irregular	133,599	M		U	U		U
Don't know	196,480	A	125,877	M	U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 2.3

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
7,139,542	A	623,332	A	1,643,400	A	2,927,273	A	1,386,050	A	559,488	A
1,012,963	A	81,886	A	154,041	M	358,158	A	108,013	A	310,866	A
959,836	A	36,938	A	191,575	A	267,166	A	165,776	A	298,381	A
138,495	A		U		U		U		U		U
170,067	A		U		U		U		U		U
130,707	M	29,339	M		U		U		U		U
6,171,949	A	463,517	A	1,587,174	A	2,365,888	A	1,248,100	A	507,270	A
1,723,767	A	215,142	A	183,294	A	782,406	A	208,780	A	334,145	A
	U		U		U		U		U		U
1,517,779	A	231,963	A	241,728	A	614,858	A	272,647	A	156,582	A
225,745	A	37,959	M		U		U		U		U
458,748	A		U		U	248,866	A	72,886	A		U
708,397	A	48,944	A	146,336	A	338,343	A	108,553	A	66,221	M
4,520,682	A	311,958	A	1,162,540	A	1,669,121	A	905,967	A	471,097	A
143,725	A		U		U		U		U		U
322,357	A		U		U		U	55,901	M	69,200	M

2.4 Heated area

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Heated area of basement								
56 square metres or less (600 square feet or less)	847,319	A	429,990	A		U		U
56 to 93 square metres (601 to 1,000 square feet)	1,827,656	A	402,579	A		U		U
93 to 139 square metres (1,001 to 1,500 square feet)	1,714,902	A	163,892	M		U		U
139 or more square metres (1,501 or more square feet)	480,352	A		U		U		U
Heated area of dwelling								
56 square metres or less (600 square feet or less)	221,245	A	113,183	M	630,036	A		U
56 to 93 square metres (601 to 1,000 square feet)	1,619,873	A	483,828	A	965,964	A	102,862	A
93 to 139 square metres (1,001 to 1,500 square feet)	2,827,916	A	793,196	A	322,733	A	68,426	A
139 to 186 square metres (1,501 to 2,000 square feet)	1,468,244	A	242,692	A		U		U
186 to 232 square metres (2,001 to 2,500 square feet)	497,079	A		U		U		U
232 or more square metres (2,501 or more square feet)	557,183	A		U		U		U
Heated area of building (excluding indoor parking)								
167 square metres or less (1,800 square feet or less)		U		U		U		U
167 to 279 square metres (1,801 to 3,000 square feet)		U	192,334	A	361,543	A		U
279 to 418 square metres (3,001 to 4,500 square feet)		U		U	161,150	A		U
418 to 557 square metres (4,501 to 6,000 square feet)		U		U	187,492	A		U
558 or more square metres (6,001 or more square feet)		U		U	1,251,657	A		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 2.4

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
1,280,084	A	106,577	A	242,219	A	630,145	A	222,605	A		U
2,234,344	A	155,309	A	704,395	A	774,010	A	431,346	A	169,284	A
1,878,794	A	150,243	A	446,453	A	639,553	A	483,018	A	159,527	A
539,425	A	39,050	M	133,044	M	243,757	A	80,032	A		U
978,692	A	68,990	A	429,837	A	261,461	A	129,201	M	89,203	M
3,172,527	A	311,997	A	1,105,823	A	694,243	A	627,132	A	433,333	A
4,012,272	A	324,257	A	920,708	A	1,514,290	A	755,236	A	497,781	A
1,779,867	A	124,129	A	339,196	A	784,415	A	298,580	A	233,547	A
566,289	A	31,853	M	89,470	M	289,940	A		U	101,448	M
659,742	A		U	99,210	M	337,683	A		U	144,696	A
173,550	M		U	101,077	M		U		U		U
553,877	A		U	363,093	A		U		U		U
274,034	M		U	172,527	A		U		U		U
	U		U	129,596	A		U		U		U
1,262,593	A	83,489	A	424,439	A	253,977	A	177,204	A	323,484	A

2.5 Garage

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment	Mobile home	
Dwellings with a garage							
Yes	4,184,374	A	625,833	A	U		U
No	3,007,166	A	1,095,583	A	U	170,922	A
Garage attached to dwelling							
Yes	2,945,380	A	488,676	A	U		U
No	1,238,994	A	137,157	M	U		U
Insulated garage							
Yes	2,137,187	A	297,160	A	U		U
No	2,002,967	A	320,345	A	U		U
Don't know		U		U	U		U
Garage usually heated during heating season							
Yes	519,701	A	65,378	M	U		U
No	3,664,673	A	560,455	A	U		U
Type of garage							
One-car garage	1,291,096	A	420,024	A	U		U
Two-car garage	1,715,321	A		U	U		U
Three-or-more-car garage	121,500	M		U	U		U
Don't know		U		U	U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 2.5

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
4,834,461 A	235,532 A	644,634 A	2,235,613 A	1,045,320 A	673,362 A
4,273,671 A	551,747 A	1,377,388 A	1,226,453 A	639,389 A	478,695 A
3,437,598 A	132,051 A	444,730 A	1,763,050 A	552,480 A	545,287 A
1,396,863 A	103,480 A	199,904 A	472,563 A	492,840 A	128,075 A
2,441,583 A	123,128 A	420,449 A	859,816 A	598,326 A	439,865 A
2,340 330 A	111,833 A	222,029 A	1,342,116 A	442,573 A	221,778 A
U	U	U	U	U	U
587,820 A	U	229,128 A	139,122 A	145,426 A	U
4,246,641 A	203,588 A	415,507 A	2,096,491 A	899,893 A	631,162 A
1,714,662 A	82,127 A	395,396 A	846,590 A	169,809 A	220,741 A
1,807,767 A	56,790 A	103,091 M	914,732 A	415,991 A	317,163 A
123,621 M	U	U	U	U	U
U	U	U	U	U	U

2.6 Attics / crawl spaces

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Dwellings with an attic or a crawl space								
Yes	5,892,453	A	1,006,013	A		U		U
No	1,290,391	A	677,751	A		U	166,776	A
Don't know		U		U		U		U
Attic or crawl space insulated								
Yes	5,266,101	A	827,520	A		U		U
No	454,136	A	67,447	M		U		U
Don't know	180,911	A	148,698	M		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 2.6

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
6,923,010 A	643,793 A	1,503,085 A	2,580,807 A	1,339,595 A	855,730 A
2,134,918 A	143,486 A	502,183 A	865,561 A	341,030 A	282,659 A
U	U	U	U	U	U
6,115,777 A	558,921 A	1,362,358 A	2,303,295 A	1,150,092 A	741,111 A
523,972 A	72,564 A	118,994 M	157,332 M	106,031 M	69,052 A
333,465 A	U	U	135,878 M	U	U

2.7 Window upgrades

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Number of windows replaced or added in 2003								
0	6,032,628	A	1,449,227	A	1,680,544	A	156,811	A
1 or 2	468,493	A	88,224	M		U		U
3 or 4	179,762	A		U		U		U
5 to 10	264,538	A		U		U		U
11 to 50	81,356	M		U		U		U
51 or more		U		U		U		U
Don't know	164,763	A	122,466	M	130,605	M		U
Type of windows installed in 2003								
Low-E coating gas-filled double pane	290,652	A		U		U		U
Gas-filled double pane	229,273	A		U		U		U
Standard double pane	327,535	A		U	104,454	M		U
Low-E coating gas-filled triple pane		U		U		U		U
Gas-filled triple pane		U		U		U		U
Standard triple pane		U		U		U		U
Don't know	184,644	A	126,344	M	141,606	M		U
Improvements made to the caulking or weatherstripping of windows in 2003								
Yes	1,124,223	A	177,933	A	178,357	A		U
No	6,064,120	A	1,543,483	A	1,854,697	A	166,166	A
Don't know		U		U		U		U
Number of windows in which the caulking or weatherstripping was improved in 2003								
1 or 2	249,834	A		U	78,779	M		U
3 or 4	286,076	A		U		U		U
5 or more	570,640	A	93,583	M		U		U
Don't know		U		U		U		U
Plastic film put on windows during the heating season								
Yes	956,369	A	260,837	A	193,927	A	45,460	M
No	6,235,171	A	1,460,579	A	1,863,909	A	149,716	A
Don't know		U		U		U		U
Condensation on the inside surfaces of windows								
Yes, on most of the windows	701,658	A	201,846	A	414,775	A		U
Yes, on some windows	2,193,011	A	585,065	A	531,550	A	69,332	A
No	4,296,871	A	934,505	A	1,114,931	A	99,569	A
Air leaks or drafts around windows								
Yes	1,930,413	A	734,198	A	905,315	A	58,707	A
No	5,253,602	A	984,614	A	1,155,942	A	136,469	A
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 2.7

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
9,319,210	A	755,642	A	2,466,965	A	3,241,218	A	1,612,918	A	1,242,466	A
642,630	A	65,402	A	169,591	A	238,624	A	84,155	A	84,858	M
244,725	A		U		U		U		U	41,616	M
378,003	A		U	118,242	A	111,988	M	72,342	M		U
144,673	A		U		U		U		U		U
	U		U		U		U		U		U
432,233	A		U	118,868	M	159,154	M	76,132	M	62,568	M
352,785	A		U		U	154,988	A		U		U
348,274	A		U	138,388	A	130,930	M		U		U
511,032	A	66,218	A	165,607	A	125,663	M	62,266	M	91,277	M
	U		U		U		U		U		U
	U		U		U		U		U		U
69,558	M		U		U		U		U		U
466,995	A		U	124,309	M	172,014	M	82,578	M	66,697	M
1,509,524	A	134,038	A	381,079	A	652,481	A	217,147	A	124,780	A
9,628,465	A	766,304	A	2,599,177	A	3,210,117	A	1,677,638	A	1,375,229	A
	U		U		U		U		U		U
372,011	A	51,142	A	108,001	M	119,494	M	60,884	M		U
372,400	A		U		U	168,092	M	57,541	M		U
742,429	A	52,298	A	187,188	A	344,714	A	97,276	A	60,954	M
	U		U		U		U		U		U
1,456,594	A	92,630	A	431,189	A	495,192	A	337,405	A	100,178	A
9,709,375	A	807,712	A	2,553,055	A	3,386,839	A	1,565,358	A	1,396,411	A
	U		U		U		U		U		U
1,344,555	A	74,860	A	442,433	A	365,808	A	305,762	A	155,692	A
3,378,958	A	289,995	A	989,427	A	1,194,971	A	559,576	A	344,990	A
6,445,876	A	535,487	A	1,552,384	A	2,321,253	A	1,037,425	A	999,327	A
3,628,633	A	336,494	A	914,282	A	1,245,932	A	775,136	A	356,789	A
7,530,626	A	562,396	A	2,069,962	A	2,628,735	A	1,127,627	A	1,141,905	A
	U		U		U		U		U		U

2.8 Dwelling upgrades

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Improvements made to dwellings to reduce energy use in 2003								
The roof structure or surface	403,639	A		U	156,168	M		U
The exterior wall siding	176,942	A		U		U		U
The insulation of the roof or the attic	178,296	A		U		U		U
The insulation of the basement or crawl space walls	241,140	A		U		U		U
The insulation of any exterior walls (excluding the basement)	141,223	A		U		U		U
The foundation		U		U		U		U
The heating equipment	265,790	A		U		U		U
The ventilation or air-conditioning equipment	112,295	A		U		U		U
None of the above	5,905,611	A	1,360,202	A	1,599,895	A	144,057	A
Don't know	163,382	A	121,266	M	136,783	M		U
Planning to make improvements in 2004 to reduce energy use								
The roof structure or surface	392,116	A		U	85,152	M		U
The exterior wall siding	181,267	A		U		U		U
The insulation of the roof or the attic	241,969	A		U		U		U
The insulation of the basement or crawl space walls	215,235	A		U		U		U
The insulation of any exterior walls (excluding the basement)	207,926	A		U		U		U
The foundation		U		U		U		U
The heating equipment	211,438	A		U		U		U
The ventilation or air-conditioning equipment	79,471	M		U		U		U
None of the above	5,734,451	A	1,349,894	A	1,608,120	A	146,487	A
Don't know	195,695	A	130,362	A	183,029	A		U
Reason for not making or planning on making any improvements								
No improvements necessary	3,448,908	A	809,116	A	914,931	A	65,922	M
Improvements too costly	901,031	A	190,774	A	233,407	A		U
Not aware of government financial aid or assistance		U		U		U		U
No government financial aid or assistance		U		U		U		U
Don't have time	67,655	M		U		U		U
Other	471,231	A	152,990	M	208,258	A		U
Don't know	165,242	A	118,816	M	135,300	A		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 2.8

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
638,545 A	69,826 A	163,482 A	263,256 A	65,914 M	76,067 M
286,091 A	23,986 M	126,986 M	U	U	U
248,241 A	U	U	U	U	U
338,096 A	U	98,062 M	149,199 M	U	U
214,862 A	U	U	U	U	U
81,517 M	U	U	U	U	U
425,166 A	37,842 M	78,842 M	205,279 M	U	44,838 M
186,964 A	U	U	U	U	U
9,009,765 A	712,584 A	2,444,626 A	3,011,471 A	1,601,425 A	1,239,658 A
435,830 A	U	134,699 A	147,860 M	U	69,396 M
551,373 A	58,321 A	99,327 M	232,419 A	84,490 M	76,817 M
294,870 A	39,790 M	U	U	U	U
344,625 A	U	U	U	U	U
283,795 A	37,160 M	U	U	U	U
272,256 A	U	U	U	U	U
75,893 M	U	U	U	U	U
355,221 A	U	U	156,484 M	55,815 M	U
111,252 A	U	U	U	U	U
8,838,952 A	695,742 A	2,425,349 A	3,023,054 A	1,533,662 A	1,161,144 A
523,486 A	U	139,337 A	192,614 M	79,596 M	89,466 M
5,238,876 A	384,499 A	1,481,298 A	1,730,841 A	853,690 A	788,548 A
1,345,613 A	110,060 A	318,328 A	406,168 A	342,001 A	169,056 A
68,853 M	U	U	U	U	U
U	U	U	U	U	U
117,242 M	U	U	U	U	U
857,987 A	57,795 A	226,656 A	359,736 A	131,048 M	82,752 M
433,757 A	U	130,382 M	148,741 M	69,459 M	68,899 M

SECTION 3

Heating System

3.1 Profile of heating system

BY TYPE OF DWELLING

	Single detached	Double/row house	Apartment	Mobile home
Dwellings with central heating unit or heating unit used by their household only				
Central unit	U	U	759,220 A	U
Dwelling unit	U	160,705 A	1,178,013 A	U
Households with a heat pump				
Yes	306,543 A	U	U	U
No	6,869,752 A	1,675,466 A	1,966,726 A	192,796 A
Don’t know	U	U	U	U
Type of heat pump				
Air source	259,765 A	U	U	U
Ground source	U	U	U	U
Don’t know	U	U	U	U
Households with a heat pump that is used as a back-up furnace				
Yes	249,142 A	U	U	U
No	57,401 M	U	U	U
Type of main heating equipment				
Furnace with forced air (hot air vents)	4,647,469 A	1,015,557 A	129,676 M	113,405 A
Electric baseboards	1,215,268 A	490,791 A	1,133,699 A	52,040 M
Heating stove (burning wood, pellets, corn, coal, etc.)	365,671 A	U	U	U
Furnace (boiler) with hot water or steam radiators	399,510 A	123,992 M	650,499 A	U
Electric radiant heating	U	U	U	U
Other equipment	221,691 A	U	U	U
Age of main heating equipment				
3 years old or less	912,193 A	189,458 A	140,285 M	U
4 to 5 years old	594,209 A	91,651 M	111,201 M	U
6 to 10 years old	1,567,408 A	336,464 A	298,607 A	61,952 A
11 to 15 years old	1,106,068 A	240,213 A	334,653 A	U
16 to 20 years old	879,781 A	259,830 A	332,345 A	U
21 years old or more	1,592,394 A	419,525 A	594,117 A	52,847 M
Unsure; was there when moved in	U	U	U	U
Don’t know	232,944 A	143,843 M	178,544 A	U
Age of furnace with forced air				
3 years old or less	700,942 A	148,476 M	U	U
4 to 5 years old	445,981 A	U	U	U
6 to 10 years old	1,116,150 A	250,867 A	U	U
11 to 15 years old	771,181 A	136,589 M	U	U
16 to 20 years old	585,380 A	155,879 M	U	U
21 years old or more	878,488 A	197,315 A	U	U
Unsure; was there when moved in	136,491 A	U	U	U
Don’t know	U	U	U	U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 3.1

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
828,456 A	71,090 A	208,006 A	U	164,757 A	170,044 A
1,338,718 A	58,509 A	797,252 A	206,067 A	61,453 M	215,436 A
420,289 A	U	198,872 A	131,120 M	U	U
10,704,739 A	891,653 A	2,785,372 A	3,722,199 A	1,850,115 A	1,455,399 A
U	U	U	U	U	U
313,172 A	U	195,899 A	U	U	U
U	U	U	U	U	U
U	U	U	U	U	U
297,052 A	U	161,405 A	U	U	U
123,236 M	U	U	U	U	U
5,906,108 A	275,951 A	359,834 A	2,959,771 A	1,558,811 A	751,740 A
2,891,798 A	299,802 A	1,830,803 A	319,413 A	85,423 A	356,357 A
396,992 A	77,472 A	178,482 A	U	U	91,297 M
1,174,001 A	189,693 A	312,259 A	312,492 A	183,320 A	176,237 A
86,797 M	U	U	U	U	U
293,404 A	U	U	U	U	U
1,260,287 A	107,373 A	218,922 A	572,381 A	256,599 A	105,013 A
816,267 A	78,787 A	126,761 M	344,688 A	146,599 A	119,432 M
2,264,431 A	207,706 A	451,913 A	926,135 A	351,942 A	326,736 A
1,695,715 A	169,877 A	406,688 A	684,225 A	210,074 A	224,850 A
1,492,548 A	123,979 A	426,181 A	440,813 A	276,476 A	225,099 A
2,658,883 A	176,720 A	959,966 A	608,103 A	513,608 A	400,486 A
U	U	U	U	U	U
560,968 A	27,783 M	194,941 A	174,565 M	101,113 A	62,565 M
875,523 A	37,205 A	U	502,148 A	239,842 A	59,452 M
544,087 A	U	U	322,357 A	119,296 A	53,904 M
1,424,726 A	85,192 A	U	774,810 A	307,151 A	164,336 A
950,428 A	42,288 A	U	528,270 A	178,960 A	132,976 A
782,731 A	37,070 M	U	358,898 A	237,352 A	117,197 A
1,112,442 A	38,996 A	105,244 M	389,550 A	394,743 A	183,909 A
187,431 A	U	U	U	75,324 M	U
U	U	U	U	U	U

3.1 Profile of heating system

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Age of furnace with hot water or steam radiators								
3 years old or less		U		U		U		U
4 to 5 years old		U		U		U		U
6 to 10 years old	122,079	M		U	125,761	M		U
11 to 15 years old	50,672	M		U		U		U
16 to 20 years old		U		U		U		U
21 years old or more	91,916	M		U	231,461	A		U
Unsure; was there when moved in		U		U		U		U
Don't know		U		U		U		U
Age of heating stove								
3 years old or less	59,567	M		U		U		U
4 to 5 years old		U		U		U		U
6 to 10 years old	76,289	M		U		U		U
11 to 15 years old		U		U		U		U
16 to 20 years old		U		U		U		U
21 years old or more		U		U		U		U
Unsure; was there when moved in		U		U		U		U
Don't know		U		U		U		U
Age of electric baseboards								
3 years old or less	63,110	M		U		U		U
4 to 5 years old		U		U		U		U
6 to 10 years old	179,733	A		U	137,239	A		U
11 to 15 years old	186,870	A	82,421	M	228,074	A		U
16 to 20 years old	176,142	A	79,263	M	221,227	A		U
21 years old or more	515,720	A	153,856	A	335,050	A		U
Unsure; was there when moved in		U		U	144,216	M		U
Don't know		U		U		U		U
Households with an ENERGY STAR® furnace								
Yes	532,761	A		U		U		U
No	103,538	A		U		U		U
Don't know	121,297	A		U		U		U
Furnace/heating stove uses one or two energy sources								
One source	4,865,980	A	1,077,769	A	726,600	A	130,682	A
Two sources	546,671	A		U		U		U
Hot-air furnace uses one or two energy sources								
One source	4,177,879	A	958,700	A	126,592	M	107,721	A
Two sources	469,590	A		U		U		U
Furnace with hot water or steam radiators uses one or two energy sources								
One source	351,734	A	112,557	M	598,160	A		U
Two sources		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 3.1 (cont. 2/3)

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
116,437	M		U		U		U		U		U
101,509	M		U		U		U		U		U
259,358	A	48,807	A		U		U		U		U
121,400	M		U		U		U		U		U
146,423	A		U		U		U		U		U
379,393	A	46,463	M	123,616	M		U	81,605	M		U
	U		U		U		U		U		U
	U		U		U		U		U		U
59,567	M		U		U		U		U		U
	U		U		U		U		U		U
100,978	A		U		U		U		U		U
	U		U		U		U		U		U
	U		U		U		U		U		U
57,462	M		U		U		U		U		U
	U		U		U		U		U		U
	U		U		U		U		U		U
155,425	A		U	111,996	M		U		U		U
82,898	M		U		U		U		U		U
370,240	A	48,397	A	231,954	A		U		U	76,440	A
502,406	A	66,471	A	271,372	A		U		U		U
482,752	A	54,604	A	316,225	A		U		U	59,873	M
1,032,064	A	76,006	A	679,129	A	119,433	M		U	133,579	A
246,886	A		U	144,146	M		U		U		U
	U		U		U		U		U		U
665,691	A	43,322	A		U	387,859	A	158,980	A	51,620	M
139,806	A		U		U		U		U		U
217,302	A		U		U		U		U		U
6,801,030	A	473,606	A	658,769	A	3,119,339	A	1,579,337	A	969,979	A
676,070	A	69,511	A	191,806	A	190,919	A	174,539	A		U
5,370,891	A	229,902	A	234,801	A	2,792,430	A	1,404,011	A	709,747	A
535,216	A	46,049	M	125,033	M	167,340	A	154,800	A		U
1,062,451	A	170,307	A	254,213	A	299,863	A	165,948	A	172,120	A
111,549	M		U		U		U		U		U

3.1 Profile of heating system

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Heating stove uses one or two energy sources								
One source	336,366	A		U		U		U
Two sources		U		U		U		U
Source(s) of energy for hot-air furnace								
Electricity	541,169	A	94,450	M		U		U
Natural gas	3,597,487	A	899,581	A		U	72,899	A
Oil	724,159	A	73,048	M		U		U
Wood	142,107	A		U		U		U
Propane		U		U		U		U
Other		U		U		U		U
Source(s) of energy for hot-water furnace								
Electricity	65,626	M		U		U		U
Natural gas	174,890	A		U	499,113	A		U
Oil	178,851	A		U	128,938	A		U
Wood		U		U		U		U
Propane		U		U		U		U
Other		U		U		U		U
Source(s) of energy for heating stove								
Electricity		U		U		U		U
Natural gas		U		U		U		U
Oil		U		U		U		U
Wood	324,955	A		U		U		U
Propane		U		U		U		U
Other		U		U		U		U
Households with a high-efficiency furnace (condensing furnace)								
Yes	1,911,369	A	337,775	A	173,542	A		U
No	2,599,806	A	694,554	A	477,862	A	69,039	A
Don't know	224,472	A		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 3.1 (cont. 3/3)

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
367,688	A	73,396	A	169,755	A		U		U	88,112	M
	U		U		U		U		U		U
672,053	A		U	165,481	M	220,680	A	193,135	A	75,059	M
4,660,710	A		U		U	2,503,750	A	1,464,258	A	637,336	A
826,683	A	232,708	A	208,669	A	305,856	A		U		U
142,107	A	57,924	A		U		U		U		U
79,531	M		U		U		U		U		U
	U		U		U		U		U		U
158,010	A		U	97,282	M		U		U		U
730,759	A		U	121,317	M	274,242	A	167,607	A	165,128	A
358,274	A	176,356	A	151,706	A		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
354,035	A	74,472	A	161,568	A		U		U	78,997	M
	U		U		U		U		U		U
	U		U		U		U		U		U
2,452,901	A	121,548	A	120,756	M	1,489,249	A	481,259	A	240,088	A
3,841,260	A	276,372	A	383,296	A	1,524,243	A	1,094,084	A	563,266	A
361,796	A		U		U	133,642	M	94,897	M	75,124	M

3.2 Characteristics of supplementary heating system

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a supplementary heating system								
Yes	2,224,734	A	323,668	A	160,103	M	69,223	A
No	4,966,806	A	1,397,748	A	1,901,154	A	125,953	A
Main type of supplementary heating system								
Electric baseboards	699,849	A		U		U		U
Portable electric heater	598,575	A	189,526	A	105,543	M		U
Wood stove	491,929	A		U		U		U
Furnace	158,712	M		U		U		U
Other	275,668	A		U		U		U
Weekly use of supplementary heating during the heating season								
Don't use it	129,837	M		U		U		U
50 hours or less	1,378,511	A	243,089	A	119,328	M		U
51 to 100 hours	182,080	A		U		U		U
101 to 168 hours	453,794	A		U		U		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 3.2

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
2,777,728	A	258,530	A	808,934	A	909,390	A	316,491	A	484,383	A
8,391,661	A	641,812	A	2,175,310	A	2,972,641	A	1,586,272	A	1,015,626	A
817,511	A	78,158	A	338,513	A	207,175	A	49,744	M	143,920	A
917,629	A		U	96,265	M	423,638	A	181,531	A	190,379	A
522,745	A	94,135	A	240,165	A		U	33,944	M	60,532	M
170,956	M		U		U		U		U		U
348,887	A	28,811	A	77,518	M	154,715	M	39,676	M	48,168	M
156,792	A		U		U		U		U		U
1,787,857	A	153,338	A	516,567	A	577,879	A	215,536	A	324,538	A
215,520	A		U		U		U		U		U
524,414	A	39,259	A	177,861	A	186,301	A	56,428	A	64,566	M
93,145	M		U		U		U		U		U

3.3 Characteristics of wood fireplaces

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Use of wood (cords)								
0	859,334	A	94,401	M		U		U
1 cord or less	652,658	A		U		U		U
2 to 3 cords	512,863	A		U		U		U
4 to 5 cords	292,854	A		U		U		U
6 or more	417,089	A		U		U		U
Use wood that cannot be measured in cords	179,640	A		U		U		U
Don't know		U		U		U		U
Type of cords used								
Face or stove cord (approximately 16 inches x 8 feet x 4 feet)	948,567	A		U		U		U
Full or bush cord (4 feet x 8 feet x 4 feet)	867,358	A		U		U		U
Don't know	90,812	M		U		U		U
Households with a wood-burning fireplace								
Yes	2,224,384	A	254,867	A		U		U
No	4,967,156	A	1,466,549	A	1,992,506	A	186,862	A
Number of wood-burning fireplaces								
0	4,967,156	A	1,466,549	A	1,992,506	A	186,862	A
1	1,903,175	A	240,253	A		U		U
2 to 4	321,209	A		U		U		U
Age of main wood-burning fireplace								
Less than 4 years old	147,515	M		U		U		U
4 to 6 years old	138,522	A		U		U		U
7 to 10 years old	193,379	A		U		U		U
11 years old or more	1,328,057	A	160,340	M		U		U
Unsure; was there when moved in	407,807	A		U		U		U
Don't know		U		U		U		U
Main wood-burning fireplace with glass doors								
Yes	1,303,300	A	119,254	M		U		U
No	921,084	A	135,614	A		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published. Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 3.3

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
985,512 A	75,241 A	106,929 M	436,815 A	156,186 A	210,341 A
745,709 A	43,407 M	205,063 A	246,869 A	155,256 A	95,114 A
559,012 A	82,114 A	198,963 A	158,434 M	45,153 M	74,348 M
322,123 A	79,430 A	136,917 M	U	U	U
434,900 A	46,663 M	258,851 A	U	U	U
242,184 A	U	U	132,016 M	U	U
U	U	U	U	U	U
1,032,018 A	89,590 A	486,957 A	297,736 A	97,784 A	59,951 M
953,309 A	149,655 A	303,132 A	208,535 A	126,662 A	165,325 M
111,663 A	U	U	U	U	U
2,556,317 A	133,915 A	626,187 A	980,797 A	390,236 A	425,181 A
8,613,072 A	766,427 A	2,358,057 A	2,901,234 A	1,512,527 A	1,074,828 A
8,613,072 A	766,427 A	2,358,057 A	2,901,234 A	1,512,527 A	1,074,828 A
2,217,094 A	116,365 A	553,901 A	863,685 A	351,661 A	331,483 A
339,223 A	U	U	117,111 M	U	93,699 A
173,710 M	U	83,696 M	U	U	U
143,902 A	U	U	U	U	U
204,622 A	U	103,270 M	U	U	U
1,528,651 A	89,643 A	317,474 A	593,807 A	260,250 A	267,476 A
496,328 A	U	U	273,301 A	U	82,225 M
U	U	U	U	U	U
1,460,458 A	66,477 A	433,790 A	577,395 A	200,586 A	182,210 A
1,095,858 A	67,438 A	192,397 A	403,401 A	189,650 A	242,972 A

3.4 Characteristics of gas fireplaces

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a gas fireplace								
Yes	1,482,217	A	258,083	A	93,799	A		U
No	5,709,323	A	1,463,333	A	1,967,458	A	186,283	A
Number of gas fireplaces								
0	5,709,323	A	1,463,333	A	1,967,458	A	186,283	A
1	1,173,039	A	246,432	A	93,799	A		U
2 to 4	309,178	A		U		U		U
Age of main gas fireplace								
Less than 4 years old	340,744	A		U		U		U
4 to 6 years old	392,987	A		U		U		U
7 to 10 years old	384,029	A		U		U		U
11 years old or more	307,608	A		U		U		U
Unsure; was there when moved in		U		U		U		U
Main gas-burning fireplace with glass doors								
Yes	1,331,950	A	211,045	A		U		U
No	150,267	A		U		U		U
Main gas-burning fireplace installed where a wood-burning fireplace previously existed								
Yes	420,529	A		U		U		U
No	1,045,568	A	220,949	A	93,799	A		U
Don't know		U		U		U		U
Main gas fireplace with pilot light								
Yes	1,423,642	A	251,535	A	82,400	M		U
No		U		U		U		U
Don't know		U		U		U		U
Pilot light turned off in the summer								
Yes	838,313	A	144,007	M		U		U
No	580,201	A	107,528	A		U		U
Don't know		U		U		U		U
Type of exhaust for main gas fireplace								
Out the chimney	715,342	A	153,199	M		U		U
Out the side wall (direct vent)	766,875	A		U		U		U
Don't know		U		U		U		U
Use of gas fireplace during heating season								
Every day	511,915	A		U		U		U
Several times a week	266,966	A		U		U		U
A few times a week	223,518	A		U		U		U
A few times a month	304,697	A		U		U		U
Never	173,362	A		U		U		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 3.4

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
1,842,993 A	49,146 A	U	903,029 A	304,969 A	504,663 A
9,326,396 A	851,196 A	2,903,058 A	2,979,002 A	1,597,794 A	995,346 A
9,326,396 A	851,196 A	2,903,058 A	2,979,002 A	1,597,794 A	995,346 A
1,522,164 A	48,093 A	U	805,542 A	272,628 A	358,860 A
320,829 A	U	U	U	U	145,803 A
418,350 A	U	U	204,023 M	66,422 M	66,368 M
442,325 A	U	U	236,659 A	75,380 A	95,692 A
521,567 A	U	U	240,239 A	107,200 A	166,069 A
382,833 A	U	U	170,951 A	U	155,908 A
77,918 M	U	U	U	U	U
1,608,828 A	41,439 A	U	808,039 A	263,859 A	414,304 A
234,165 A	U	U	U	U	90,359 M
457,172 A	U	U	244,019 A	U	135,959 A
1,366,823 A	U	U	647,381 A	258,362 A	361,336 A
U	U	U	U	U	U
1,765,790 A	49,146 A	U	880,826 A	288,587 A	466,045 A
U	U	U	U	U	U
U	U	U	U	U	U
1,045,284 A	U	U	542,552 A	132,051 A	301,997 A
715,377 A	U	U	333,933 A	156,536 A	163,261 A
U	U	U	U	U	U
908,516 A	U	U	426,982 A	140,594 A	306,015 A
925,337 A	U	U	476,047 A	161,869 A	192,014 A
U	U	U	U	U	U
656,222 A	U	U	332,596 A	85,411 A	194,922 A
291,749 A	U	U	166,419 M	U	U
280,265 A	U	U	167,805 M	U	55,472 M
389,686 A	U	U	146,313 A	103,626 A	123,971 A
223,310 A	U	U	U	U	91,072 M
U	U	U	U	U	U

3.5 Presence of occupants

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with someone at home all day								
Yes	4,238,534	A	894,552	A	968,188	A	123,300	A
No	2,946,925	A	826,865	A	1,091,104	A	71,876	A
Don't know		U		U		U		U
Number of weeks with no one at the dwelling								
0	4,191,805	A	945,046	A	1,132,576	A	108,663	A
1 to 2 weeks	1,445,469	A	450,795	A	422,842	A		U
3 to 4 weeks	889,372	A	184,695	A	226,354	A		U
5 weeks or more	652,542	A	136,529	A	266,741	A		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 3.5

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
6,224,573	A	524,417	A	1,652,348	A	2,262,779	A	929,915	A	855,114	A
4,936,770	A	375,925	A	1,331,896	A	1,616,398	A	972,848	A	639,703	A
	U		U		U		U		U		U
6,378,090	A	578,859	A	1,783,197	A	2,255,876	A	992,068	A	768,090	A
2,357,852	A	164,077	A	546,975	A	874,341	A	452,842	A	319,617	A
1,335,588	A	67,984	A	363,509	A	433,780	A	259,383	A	210,932	A
1,068,413	A	87,612	A	282,236	A	309,341	A	192,465	A	196,759	A
	U		U		U		U		U		U

3.6 Energy sources used

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Electricity is used by the household as an energy source								
Yes	7,191,540	A	1,717,522	A	2,061,257	A	195,176	A
No		U		U		U		U
Natural gas is used by the household as an energy source								
Yes	4,080,501	A	1,031,726	A	886,824	A	74,084	A
No	3,111,039	A	689,690	A	1,174,432	A	121,092	A
Heating oil is used by the household as an energy source								
Yes	1,072,062	A	146,086	A	167,225	A		U
No	6,119,478	A	1,575,330	A	1,894,032	A	179,841	A
Propane gas is used by the household as an energy source								
Yes	292,026	A		U		U		U
No	6,899,514	A	1,714,328	A	2,060,872	A	167,235	A
Wood is used by the household as an energy source								
Yes	2,945,711	A	273,225	A		U		U
No	4,245,829	A	1,448,191	A	1,992,506	A	158,179	A

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 3.6

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
11,165,495	A	900,342	A	2,984,244	A	3,882,031	A	1,898,869	A	1,500,009	A
	U		U		U		U		U		U
6,073,136	A		U	272,969	A	3,019,029	A	1,718,806	A	1,058,833	A
5,096,253	A	896,842	A	2,711,275	A	863,002	A	183,957	A	441,176	A
1,400,708	A	452,717	A	473,067	A	372,008	A		U		U
9,768,681	A	447,625	A	2,511,177	A	3,510,023	A	1,874,341	A	1,425,514	A
327,440	A	72,476	A		U		U		U		U
10,841,949	A	827,866	A	2,874,976	A	3,794,322	A	1,883,256	A	1,461,528	A
3,324,685	A	348,189	A	943,882	A	1,104,834	A	434,849	A	492,930	A
7,844,704	A	552,153	A	2,040,362	A	2,777,197	A	1,467,914	A	1,007,079	A

3.7 Temperature of living space

BY TYPE OF DWELLING

	Single detached	Double/row house	Apartment	Mobile home
Temperature of dwelling during the heating season in the daytime				
16°C or less	519,077 A	185,184 A	283,143 A	U
17°C	301,042 A	U	81,236 M	U
18°C	772,045 A	147,045 A	188,363 A	U
19°C	474,223 A	120,701 M	U	U
20°C	2,229,034 A	426,498 A	460,887 A	48,896 M
21°C	1,312,040 A	366,182 A	316,301 A	59,530 A
22°C	818,034 A	254,949 A	190,197 A	U
23°C	394,342 A	U	U	U
24°C or more	291,409 A	U	134,281 M	U
No control of the temperature	63,271 M	U	203,997 A	U
Don't know	U	U	U	U
Temperature of dwelling during the heating season in the evening				
16°C or less	261,576 A	111,775 M	148,463 A	U
17°C	196,846 A	U	U	U
18°C	495,318 A	128,679 M	196,281 A	U
19°C	414,694 A	99,466 M	U	U
20°C	2,218,408 A	445,273 A	526,657 A	32,334 M
21°C	1,648,976 A	409,713 A	335,805 A	58,586 M
22°C	1,011,816 A	289,814 A	203,570 A	U
23°C	450,244 A	106,473 M	U	U
24°C or more	408,506 A	97,848 M	172,388 M	U
No control of the temperature	U	U	U	U
Don't know	U	U	U	U
Temperature of dwelling during the heating season in the night				
16°C or less	1,436,066 A	325,414 A	424,544 A	U
17°C	623,277 A	U	109,102 M	U
18°C	1,181,036 A	243,572 A	247,140 A	39,089 M
19°C	571,554 A	143,477 M	U	U
20°C	1,633,332 A	360,175 A	365,275 A	U
21°C	867,257 A	257,793 A	225,896 A	U
22°C	431,057 A	172,222 A	132,911 M	U
23°C	165,822 A	U	U	U
24°C or more	194,865 A	U	U	U
No control of the temperature	U	U	U	U
Don't know	U	U	U	U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 3.7

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
996,680 A	142,590 A	274,453 A	232,470 A	122,846 A	224,321 A
444,585 A	U	137,316 A	137,243 M	60,701 M	77,655 A
1,125,982 A	78,163 A	287,755 A	375,362 A	177,767 A	206,935 A
677,361 A	U	155,995 M	286,356 A	140,306 A	70,720 M
3,165,315 A	280,881 A	780,462 A	1,128,698 A	591,430 A	383,843 A
2,054,053 A	133,988 A	553,191 A	769,259 A	317,011 A	280,604 A
1,284,825 A	90,604 A	400,694 A	458,370 A	211,126 A	124,032 A
548,571 A	U	176,237 A	184,004 A	97,391 A	U
523,023 A	58,532 A	136,125 M	150,343 M	138,402 M	U
280,601 A	33,323 M	U	U	U	U
U	U	U	U	U	U
530,868 A	96,880 A	162,866 A	110,168 M	92,929 A	68,025 M
275,483 A	U	U	U	U	U
835,013 A	73,395 A	280,067 A	225,127 A	115,948 A	140,476 A
595,038 A	U	151,687 M	218,917 A	121,502 A	68,816 M
3,222,672 A	276,303 A	762,654 A	1,097,272 A	621,813 A	464,629 A
2,453,079 A	162,804 A	603,622 A	1,008,214 A	322,296 A	356,143 A
1,538,218 A	97,907 A	457,738 A	533,824 A	262,424 A	186,325 A
653,018 A	U	197,802 A	230,177 A	131,059 A	U
707,160 A	71,575 A	209,810 A	195,471 A	152,689 A	77,615 M
U	U	U	U	U	U
U	U	U	U	U	U
2,220,359 A	328,314 A	512,582 A	485,388 A	349,520 A	544,554 A
823,300 A	43,285 A	212,117 A	284,331 A	140,507 A	143,060 A
1,710,837 A	144,926 A	426,952 A	596,842 A	283,819 A	258,298 A
826,064 A	31,611 M	185,224 A	326,497 A	174,917 A	107,814 A
2,389,828 A	180,934 A	683,083 A	917,826 A	431,685 A	176,299 A
1,394,527 A	56,594 A	459,344 A	545,186 A	187,446 A	145,958 M
752,690 A	44,665 M	233,546 A	307,856 A	113,534 A	U
302,926 A	U	94,949 M	122,670 M	56,135 M	U
387,899 A	U	94,799 M	124,826 M	119,417 M	U
U	U	U	U	U	U
U	U	U	U	U	U

3.8 Programmable thermostats

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a programmable thermostat								
Yes	2,519,989	A	524,109	A	258,550	A		U
No	4,596,563	A	1,182,970	A	1,598,710	A	169,292	A
Don't know		U		U		U		U
Number of programmable thermostats								
0	4,596,563	A	1,182,970	A	1,598,710	A	169,292	A
1 or 2	2,297,493	A	460,784	A	175,776	A		U
3 to 5	144,433	A		U		U		U
More than 5	78,063	M		U		U		U
Don't know		U		U		U		U
Programmable thermostats that were programmed in 2003								
Yes	1,944,032	A	427,457	A	188,638	A		U
No	575,957	A	96,652	M		U		U
Don't know		U		U		U		U
Households with programmable thermostat installed in 2003								
Yes	610,969	A	133,413	M		U		U
No	1,909,020	A	390,695	A	219,170	A		U
Don't know		U		U		U		U
Number of programmable thermostats installed in 2003								
0	1,909,020	A	390,695	A	219,170	A		U
1 or 2	566,071	A	117,713	M		U		U
3 to 5		U		U		U		U
More than 5		U		U		U		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 3.8

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
3,328,122 A	116,944 A	673,436 A	1,593,437 A	538,012 A	406,294 A
7,547,536 A	747,641 A	2,239,279 A	2,164,426 A	1,323,990 A	1,072,199 A
U	U	U	U	U	U
7,547,536 A	747,641 A	2,239,279 A	2,164,426 A	1,323,990 A	1,072,199 A
2,950,969 A	102,665 A	391,061 A	1,554,165 A	531,525 A	371,552 A
270,490 A	U	210,693 A	U	U	U
106,663 M	U	71,681 M	U	U	U
U	U	U	U	U	U
2,573,591 A	91,516 A	510,509 A	1,208,325 A	431,544 A	331,697 A
754,531 A	U	162,926 A	385,112 A	106,468 A	74,597 M
U	U	U	U	U	U
786,572 A	U	177,598 A	316,716 A	135,864 A	127,614 M
2,541,550 A	88,164 A	495,838 A	1,276,721 A	402,148 A	278,680 A
U	U	U	U	U	U
2,541,550 A	88,164 A	495,838 A	1,276,721 A	402,148 A	278,680 A
715,556 A	U	111,982 M	316,716 A	133,123 A	127,614 M
U	U	U	U	U	U
U	U	U	U	U	U
U	U	U	U	U	U

SECTION 4

Air Conditioning and Ventilation

4.1 Central air conditioning

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a central air-conditioning system								
Yes	2,403,744	A	498,714	A		U		U
No	4,787,796	A	1,222,702	A	1,999,678	A	177,188	A
Age of central air-conditioning system								
1 to 3 years old	534,240	A	130,244	M		U		U
4 to 5 years old	272,026	A		U		U		U
6 to 10 years old	575,414	A		U		U		U
11 to 15 years old	479,529	A		U		U		U
16 to 20 years old	249,268	A		U		U		U
21 years old or more	183,870	A		U		U		U
Unsure; was there when moved in	83,462	M		U		U		U
Don't know		U		U		U		U
Households with an ENERGY STAR® central air-conditioning system								
Yes	341,450	A		U		U		U
No		U		U		U		U
Don't know	166,247	A		U		U		U
Use of central air-conditioning system in cooling season per week								
0	104,496	M		U		U		U
1 to 24 hours	710,099	A	168,038	M		U		U
25 to 72 hours	491,137	A		U		U		U
More than 72 hours	963,688	A	202,196	A		U		U
Don't know	134,324	M		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 4.1

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
2,982,025 A	U	270,583 A	2,237,451 A	346,203 A	116,966 A
8,187,364 A	889,520 A	2,713,661 A	1,644,580 A	1,556,560 A	1,383,043 A
691,709 A	U	U	497,601 A	106,177 A	U
356,819 A	U	U	285,441 A	U	U
736,404 A	U	U	566,684 A	60,617 M	U
564,064 A	U	U	440,835 A	U	U
303,639 A	U	U	219,819 A	50,998 M	U
204,951 A	U	U	136,007 M	U	U
97,023 M	U	U	U	U	U
U	U	U	U	U	U
424,903 A	U	U	308,348 A	U	U
U	U	U	U	U	U
220,494 A	U	U	168,092 M	U	U
130,626 M	U	U	97,395 M	U	U
909,712 A	U	U	639,186 A	109,742 A	50,372 M
596,524 A	U	U	429,076 A	80,211 A	U
1,190,074 A	U	82,732 M	939,536 A	141,876 A	U
155,717 M	U	U	132,258 M	U	U

4.2 Window-mounted or wall-mounted air conditioner

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a window/room air conditioner								
Yes	836,966	A	263,431	A	554,751	A	58,581	M
No	6,352,447	A	1,457,985	A	1,506,506	A	136,595	A
Don't know		U		U		U		U
Number of window/room air conditioners								
0	6,352,447	A	1,457,985	A	1,506,506	A	136,595	A
1	695,726	A	222,670	A	521,869	A	58,005	M
2 or more	141,240	A		U		U		U
Don't know		U		U		U		U
Type of main window/room air conditioner								
Louvred unit	573,082	A	195,253	A	334,141	A		U
Non-louvered unit	223,756	A		U	197,208	A		U
Don't know		U		U		U		U
Cooling capacity of main window/room air conditioner								
5,000 to 10,000 Btu	283,480	A	85,604	M	267,108	A		U
10,000 to 15,000 Btu	157,338	A		U	83,524	M		U
More than 15,000 Btu		U		U		U		U
Don't know	364,056	A		U	195,028	A		U
Age of main window/room air conditioner								
1 to 3 years old	312,786	A	112,986	M	217,512	A		U
4 to 5 years old	108,245	M		U		U		U
6 to 10 years old	176,885	A		U	116,797	M		U
11 to 15 years old	113,265	M		U		U		U
16 to 20 years old	75,006	M		U		U		U
21 years old or more		U		U		U		U
Don't know		U		U		U		U
Households with an ENERGY STAR® main window/room air conditioner								
Yes	177,112	A		U	134,833	M		U
No		U		U		U		U
Don't know		U		U		U		U
Use of main window/room air conditioner in cooling season, per week								
0		U		U		U		U
1 to 24 hours	361,962	A		U	190,667	A		U
25 to 72 hours	278,657	A		U	186,208	A		U
More than 72 hours	126,674	A		U	147,674	M		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 4.2

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
1,713,729 A	70,383 A	657,390 A	625,067 A	229,041 A	131,847 A
9,453,533 A	829,959 A	2,326,854 A	3,256,964 A	1,671,595 A	1,368,162 A
U	U	U	U	U	U
9,453,533 A	829,959 A	2,326,854 A	3,256,964 A	1,671,595 A	1,368,162 A
1,498,270 A	62,945 A	579,641 A	507,473 A	219,967 A	128,245 A
215,459 A	U	77,749 M	117,595 M	U	U
U	U	U	U	U	U
1,141,991 A	58,416 A	366,079 A	459,386 A	163,626 A	94,484 A
495,890 A	U	268,262 A	U	59,786 M	U
U	U	U	U	U	U
651,142 A	U	289,586 A	235,755 A	52,096 M	U
304,636 A	U	163,848 A	U	U	U
U	U	U	U	U	U
693,234 A	U	176,128 A	274,640 A	143,043 A	72,180 M
652,011 A	U	345,049 A	184,563 M	U	U
189,571 A	U	U	U	U	U
384,259 A	U	107,428 M	199,776 A	U	U
227,619 A	U	U	U	U	U
143,786 M	U	U	U	U	U
U	U	U	U	U	U
U	U	U	U	U	U
371,895 A	U	182,701 A	U	U	U
184,837 A	U	U	U	U	U
127,700 A	U	U	U	U	U
60,061 M	U	U	U	U	U
656,230 A	U	210,649 A	250,522 A	107,021 M	61,986 A
578,997 A	U	234,195 A	201,506 A	75,398 A	U
355,172 A	U	191,758 A	U	U	U
U	U	U	U	U	U

4.3 Air exchanger

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with an air exchanger								
Yes	1,023,920	A	118,602	A		U		U
No	6,112,755	A	1,584,622	A	1,978,500	A	171,416	A
Don't know		U		U		U		U
Households with an air exchanger with a heat recovery system								
Yes	392,829	A		U		U		U
No	538,014	A	89,730	M		U		U
Don't know	147,942	M		U		U		U
Time air exchanger is used								
All year	617,380	A		U		U		U
Heating season	111,550	M		U		U		U
Cooling season		U		U		U		U
Occasionally	148,696	A		U		U		U
Never		U		U		U		U
Other		U		U		U		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 4.3

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
1,249,038	A	194,569	A	518,016	A	310,481	A	154,944	A	71,028	M
9,847,293	A	705,773	A	2,464,782	A	3,518,424	A	1,733,888	A	1,424,427	A
	U		U		U		U		U		U
438,534	A	81,962	A	161,650	A	131,564	M		U		U
699,888	A	104,118	A	338,363	A	130,138	M	108,307	A		U
183,674	A		U		U		U		U		U
710,550	A	102,626	A	351,857	A	168,891	M	51,193	M		U
130,955	A		U		U		U		U		U
101,887	A		U		U		U		U		U
200,971	A	40,809	A		U		U		U		U
	U		U		U		U		U		U
	U		U		U		U		U		U
116,257	M		U		U		U		U		U

4.4 Ceiling fan

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a ceiling fan								
Yes	4,445,579	A	919,898	A	804,738	A	155,169	A
No	2,745,114	A	801,518	A	1,256,519	A		U
Don't know		U		U		U		U
Number of ceiling fans								
0	2,745,114	A	801,518	A	1,256,519	A		U
1	1,989,450	A	422,117	A	524,232	A	94,948	A
2 or more	2,456,129	A	497,781	A	280,506	A	60,222	A
Don't know		U		U		U		U
Use of ceiling fan during the heating season, per week								
0	2,472,759	A	587,713	A	467,166	A	83,877	A
1 to 24 hours	1,084,962	A	158,493	A	185,312	M		U
25 to 72 hours	275,341	A		U		U		U
More than 72 hours	588,787	A		U		U		U
Don't know		U		U		U		U
Use of ceiling fan during the cooling season, per week								
0	649,924	A	173,254	A	81,983	M		U
1 to 24 hours	1,859,690	A	351,309	A	266,481	A	66,934	M
25 to 72 hours	883,068	A	201,934	A	185,246	A		U
More than 72 hours	975,577	A	173,638	A	253,510	A		U
Don't know	78,167	M		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 4.4

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
6,325,384 A	566,703 A	1,765,831 A	2,216,516 A	1,077,161 A	699,172 A
4,843,158 A	333,639 A	1,218,413 A	1,665,515 A	824,755 A	800,837 A
U	U	U	U	U	U
4,843,158 A	333,639 A	1,218,413 A	1,665,515 A	824,755 A	800,837 A
3,030,746 A	251,678 A	834,020 A	947,550 A	562,982 A	434,516 A
3,294,638 A	315,025 A	931,812 A	1,268,966 A	514,179 A	264,656 A
U	U	U	U	U	U
3,611,515 A	323,887 A	1,117,543 A	1,167,091 A	609,884 A	393,110 A
1,457,584 A	141,405 A	365,523 A	512,409 A	262,624 A	175,623 A
410,004 A	U	U	176,570 M	78,514 A	66,725 M
807,145 A	59,824 A	220,890 A	341,302 A	123,379 A	61,751 M
U	U	U	U	U	U
917,883 A	87,014 A	215,356 A	309,872 A	152,856 A	152,784 A
2,544,414 A	218,086 A	735,469 A	862,374 A	413,228 A	315,258 A
1,309,933 A	142,478 A	309,663 A	497,215 A	244,689 A	115,889 A
1,434,065 A	111,065 A	476,753 A	486,121 A	251,447 A	108,679 A
119,936 M	U	U	U	U	U

SECTION 5

Electrical and Other Energy-Consuming Appliances

5.1 Refrigerator

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a refrigerator								
Yes	7,182,452	A	1,717,016	A	2,061,257	A	195,176	A
No		U		U		U		U
Number of refrigerators								
0		U		U		U		U
1	4,303,624	A	1,333,274	A	2,013,148	A	168,089	A
2	2,724,945	A	363,777	A		U		U
3 or more	153,883	A		U		U		U
Age of main refrigerator								
1 to 3 years old	1,684,936	A	352,713	A	372,979	A		U
4 to 5 years old	1,000,355	A	341,267	A	223,336	A		U
6 to 10 years old	2,036,066	A	461,665	A	523,855	A	67,941	A
11 to 15 years old	1,218,918	A	259,531	A	438,734	A		U
16 to 20 years old	667,228	A	177,891	A	232,949	A		U
21 years old or more	518,859	A	100,958	M	125,398	M		U
Don’t know		U		U	144,006	M		U
Age of secondary refrigerator								
3 years old or less	203,163	A		U		U		U
4 to 5 years old	83,373	M		U		U		U
6 to 10 years old	454,590	A		U		U		U
11 to 15 years old	381,319	A		U		U		U
16 to 20 years old	450,127	A		U		U		U
21 years old or more	727,642	A		U		U		U
Don’t know	578,614	A		U		U		U
Size of main refrigerator								
Compact (less than 7.75 cubic feet)		U		U		U		U
Small (7.76 to 12.4 cubic feet)	169,669	A		U	237,944	A		U
Medium (12.5 to 16.4 cubic feet)	2,056,653	A	605,868	A	1,055,297	A	97,841	A
Large (16.5 to 20 cubic feet)	4,271,213	A	966,994	A	701,823	A	80,358	A
Very large (more than 20 cubic feet)	650,628	A	93,074	M		U		U
Don’t know		U		U		U		U
Size of secondary refrigerator								
Compact (less than 7.75 cubic feet)	245,114	A		U		U		U
Small (7.76 to 12.4 cubic feet)	481,625	A		U		U		U
Medium (12.5 to 16.4 cubic feet)	789,266	A	122,385	M		U		U
Large (16.5 to 20 cubic feet)	765,554	A	124,168	M		U		U
Very large (more than 20 cubic feet)		U		U		U		U
Don’t know	555,089	A		U		U		U
Type of doors on main refrigerator								
Top and bottom doors with freezer on top	5,111,128	A	1,412,469	A	1,757,305	A	173,645	A
Top and bottom doors with freezer on bottom	528,496	A	94,681	M		U		U
Single door	325,566	A		U	166,650	A		U
Side-by-side doors	1,143,074	A	127,304	M		U		U
Three doors	74,188	M		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.1

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
11,155,900	A	899,835	A	2,984,244	A	3,882,031	A	1,889,781	A	1,500,009	A
	U		U		U		U		U		U
	U		U		U		U		U		U
7,818,136	A	729,755	A	2,134,972	A	2,440,628	A	1,351,609	A	1,161,171	A
3,163,917	A	162,785	A	820,513	A	1,347,253	A	516,919	A	316,448	A
173,848	A		U		U		U		U		U
2,434,356	A	155,148	A	608,490	A	906,671	A	454,542	A	309,505	A
1,585,176	A	126,851	A	411,721	A	595,871	A	279,368	A	171,365	A
3,089,527	A	284,977	A	786,761	A	1,043,570	A	491,697	A	482,522	A
1,965,737	A	165,481	A	591,375	A	687,988	A	253,366	A	267,528	A
1,102,980	A	76,620	A	348,172	A	319,077	A	206,840	A	152,271	A
754,040	A	47,428	A	205,567	A	261,125	A	154,218	A	85,702	M
224,084	A		U		U		U		U		U
262,855	A		U		U	129,809	A		U	49,342	M
116,413	M		U		U		U		U		U
564,528	A		U	101,646	M	287,440	A	87,361	A	67,075	M
430,674	A		U	126,694	M	165,994	A	52,650	M	55,506	M
497,842	A		U	171,437	A	185,718	A	68,430	M		U
820,852	A		U	265,001	A	315,808	A	158,520	A	55,502	M
644,600	A		U	136,151	M	287,144	A	122,520	A	58,204	M
	U		U		U		U		U		U
459,368	A	66,704	A		U	167,720	A	82,067	M		U
3,815,659	A	314,374	A	1,078,411	A	1,083,678	A	723,106	A	616,090	A
6,020,388	A	472,168	A	1,600,975	A	2,291,301	A	921,711	A	734,233	A
801,464	A	43,682	M	228,576	A	321,049	A	145,726	A	62,432	A
	U		U		U		U		U		U
318,933	A		U		U	139,618	A		U		U
521,397	A		U	162,663	A	198,315	A	78,719	A	49,444	M
934,206	A	43,634	A	192,525	A	385,655	A	196,715	A	115,676	A
899,924	A		U	283,287	A	436,639	A	88,977	A	59,555	M
	U		U		U		U		U		U
619,930	A		U	136,151	M	267,150	A	117,187	A	58,861	M
8,454,547	A	738,385	A	2,464,348	A	2,797,979	A	1,413,608	A	1,040,227	A
686,131	A		U	189,224	A	240,813	A	102,123	A	128,102	M
552,750	A	52,993	A	127,746	A	135,696	M	152,196	A	84,121	A
1,334,256	A	71,943	A	156,045	M	675,865	A	207,235	A	223,167	A
128,216	A		U		U		U		U		U

5.1 Refrigerator

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Type of doors on secondary refrigerator								
Top and bottom doors with freezer on top	1,410,292	A	220,372	A		U		U
Top and bottom doors with freezer on bottom		U		U		U		U
Single door	788,994	A	94,189	M		U		U
Side-by-side doors	86,788	M		U		U		U
Three doors		U		U		U		U
Not stated	552,060	A		U		U		U
Households with a main refrigerator that automatically defrosts								
Yes	6,682,924	A	1,604,054	A	1,745,928	A	182,522	A
No	479,755	A	106,512	M	315,329	A		U
Don't know		U		U		U		U
Households with a secondary refrigerator that automatically defrosts								
Yes	1,291,477	A	204,975	A		U		U
No	1,018,730	A	125,652	M		U		U
Don't know	568,620	A		U		U		U
What happened to previous refrigerator								
Kept it at home and plugged in all year	567,319	A		U		U		U
Kept it at home and plugged in when needed	125,344	M		U		U		U
Disposed of: refrigerator no longer working	1,569,191	A	238,659	A	258,124	A		U
Other	1,249,501	A	171,735	A	223,253	A		U
Not stated	182,736	A		U		U		U
Age of previous refrigerator when replaced								
3 years old or less	221,771	A		U		U		U
4 to 5 years old	107,860	M		U		U		U
6 to 10 years old	423,032	A		U		U		U
11 to 15 years old	775,917	A	134,523	M	96,622	M		U
16 to 20 years old	954,990	A	112,361	M	139,047	M		U
21 years old or more	1,033,499	A	113,667	M	146,938	A		U
This is the original/first refrigerator	1,375,252	A	323,313	A	297,455	A		U
Don't know	177,021	A		U		U		U
Households with an ice maker in the main refrigerator								
Yes	923,518	A	108,857	M		U		U
No	6,239,176	A	1,601,539	A	1,981,283	A	188,010	A
Households with an ENERGY STAR® main refrigerator								
Yes	1,253,125	A	238,715	A	205,998	A		U
No	296,791	A		U	92,132	M		U
Don't know	191,109	A	71,549	M	218,855	A		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.1 (cont. 2/2)

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
1,660,915 A	58,264 A	446,937 A	736,621 A	261,977 A	157,117 A
U	U	U	U	U	U
916,401 A	64,348 A	226,066 A	383,762 A	147,826 A	94,399 A
98,969 M	U	U	U	U	U
U	U	U	U	U	U
616,902 A	U	136,151 M	267,150 A	115,671 A	57,348 M
10,215,428 A	814,656 A	2,673,882 A	3,634,741 A	1,683,284 A	1,408,864 A
914,250 A	82,872 A	303,476 A	245,165 A	194,063 A	88,674 A
U	U	U	U	U	U
1,523,209 A	65,729 A	371,774 A	683,818 A	217,850 A	184,038 A
1,181,094 A	63,173 A	341,347 A	480,724 A	201,594 A	94,256 A
633,462 A	U	136,151 M	276,860 A	118,728 A	60,544 M
625,562 A	U	269,243 A	239,536 A	68,766 M	U
139,426 A	U	U	U	U	U
2,084,235 A	187,505 A	780,307 A	812,821 A	202,368 A	101,234 A
1,665,231 A	149,078 A	811,967 A	428,672 A	164,995 A	110,519 M
250,312 A	U	79,725 M	U	U	U
282,503 A	U	145,752 A	U	U	U
135,482 M	U	U	U	U	U
563,854 A	40,519 A	201,659 A	218,591 A	U	U
1,027,777 A	92,011 A	468,772 A	354,710 A	68,848 A	U
1,214,420 A	100,894 A	508,004 A	437,106 A	121,474 A	U
1,296,132 A	109,432 A	525,529 A	424,190 A	192,619 A	U
2,012,933 A	162,279 A	598,860 A	785,318 A	322,798 A	143,679 A
244,597 A	U	79,725 M	U	U	U
1,104,690 A	61,724 A	116,753 M	552,274 A	181,719 A	192,219 A
10,010,009 A	835,986 A	2,864,236 A	3,318,034 A	1,699,815 A	1,291,938 A
1,715,473 A	99,752 A	448,376 A	651,984 A	260,512 A	254,849 A
460,455 A	U	115,921 A	152,612 A	134,247 A	U
482,512 A	63,476 A	U	169,805 M	109,533 M	U

5.2 Kitchen stove and built-in oven

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with built-in oven or regular stove								
Yes	7,163,979	A	1,715,611	A	2,031,096	A	190,355	A
No		U		U		U		U
Type of stove								
Regular stove	6,393,801	A	1,643,151	A	2,003,550	A	175,362	A
Built-in oven with a separate cooktop	770,178	A		U		U		U
Other		U		U		U		U
Age of built-in oven or regular stove								
3 years old or less	1,471,077	A	313,195	A	262,839	A		U
4 to 5 years old	852,444	A	257,564	A	150,413	A		U
6 to 10 years old	1,867,166	A	475,244	A	463,784	A	51,285	M
11 to 15 years old	1,339,361	A	295,483	A	439,572	A		U
16 to 20 years old	794,025	A	190,046	A	300,495	A		U
21 years old or more	761,538	A	139,131	M	226,661	A		U
Don't know	78,367	M		U	187,331	A		U
Energy source of built-in oven or regular stove								
Electricity	6,508,382	A	1,577,223	A	1,974,186	A	167,921	A
Natural gas	553,665	A		U		U		U
Wood		U		U		U		U
Propane	82,900	M		U		U		U
Electricity and natural gas		U		U		U		U
Energy source of cooktop								
Electricity	644,630	A		U		U		U
Natural gas	105,283	M		U		U		U
Other		U		U		U		U
Age of separate cooktop								
3 years old or less	96,183	M		U		U		U
4 to 5 years old	63,686	M		U		U		U
6 to 10 years old	154,773	A		U		U		U
11 to 15 years old	182,886	A		U		U		U
16 to 20 years old	158,022	M		U		U		U
21 years old or more	110,932	M		U		U		U
Don't know		U		U		U		U
Use of built-in oven or regular stove								
Three or more times a day	1,235,359	A	327,550	A	321,180	A		U
Two times a day	2,134,973	A	539,258	A	528,519	A	50,523	M
Once a day	2,617,679	A	568,199	A	751,578	A	64,850	A
A few times each week	920,087	A	248,135	A	337,679	A		U
Once a week	159,606	A		U		U		U
Less than once a week	84,308	M		U		U		U
Never		U		U		U		U
Self-cleaning built-in oven or regular stove								
Yes	3,476,912	A	654,399	A	344,061	A	49,923	M
No	3,676,702	A	1,061,212	A	1,679,132	A	140,432	A
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.2

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
11,101,041 A	893,891 A	2,952,358 A	3,862,694 A	1,896,597 A	1,495,502 A
68,348 M	U	U	U	U	U
10,215,864 A	814,546 A	2,692,800 A	3,590,107 A	1,780,884 A	1,337,527 A
885,177 A	79,345 A	259,558 A	272,587 A	115,712 A	157,975 A
68,348 M	U	U	U	U	U
2,066,070 A	150,803 A	531,867 A	775,229 A	350,438 A	257,733 A
1,280,275 A	105,253 A	282,823 A	498,587 A	241,788 A	151,824 A
2,857,479 A	250,745 A	727,237 A	961,475 A	471,743 A	446,279 A
2,122,478 A	169,959 A	623,837 A	758,187 A	296,407 A	274,088 A
1,319,019 A	89,928 A	444,751 A	383,798 A	226,625 A	173,917 A
1,144,244 A	75,667 A	297,030 A	354,198 A	258,352 A	158,996 A
311,477 A	U	U	U	U	U
10,227,712 A	861,856 A	2,902,309 A	3,365,729 A	1,770,993 A	1,326,824 A
754,482 A	U	U	471,730 A	124,024 A	136,966 A
U	U	U	U	U	U
98,780 M	U	U	U	U	U
U	U	U	U	U	U
742,732 A	76,041 A	240,741 A	221,263 A	103,025 A	101,663 A
122,180 M	U	U	U	U	U
U	U	U	U	U	U
106,488 A	U	U	U	U	U
79,370 M	U	U	U	U	U
183,477 A	U	U	U	U	U
197,336 A	U	U	U	U	U
188,784 M	U	U	U	U	U
118,169 M	U	U	U	U	U
U	U	U	U	U	U
1,909,198 A	272,155 A	411,387 A	553,494 A	329,936 A	342,227 A
3,253,274 A	249,497 A	947,856 A	1,023,303 A	546,945 A	485,673 A
4,002,306 A	256,475 A	1,132,445 A	1,600,512 A	631,817 A	381,057 A
1,530,193 A	100,503 A	364,868 A	533,372 A	330,864 A	200,587 A
227,110 A	U	U	U	U	U
145,005 M	U	U	U	U	U
U	U	U	U	U	U
4,525,296 A	231,152 A	1,079,212 A	1,717,652 A	788,773 A	708,507 A
6,557,477 A	662,739 A	1,873,146 A	2,138,599 A	1,105,666 A	777,327 A
U	U	U	U	U	U

5.3 Microwave oven

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a microwave								
Yes	6,914,866	A	1,559,917	A	1,842,980	A	186,699	A
No	276,674	A	161,499	M	218,277	A		U
Use of microwave								
Less than 5 minutes per week	234,583	A		U	115,971	M		U
5 to 15 minutes per week	1,098,715	A	223,511	A	433,562	A		U
16 to 30 minutes per week	1,806,169	A	413,246	A	525,472	A	61,552	M
31 to 60 minutes per week	1,891,708	A	436,942	A	397,878	A	53,466	A
61 minutes to 2 hours per week	1,270,282	A	252,767	A	250,190	A		U
More than 2 hours per week	604,362	A	160,712	A	119,907	M		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.3

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
10,504,462	A	857,885	A	2,745,069	A	3,670,056	A	1,847,856	A	1,383,596	A
664,927	A	42,457	A	239,175	A	211,975	M		U	116,413	M
427,456	A		U		U	182,070	M		U	90,785	M
1,775,646	A	152,482	A	531,107	A	604,999	A	278,112	A	208,947	A
2,806,439	A	242,365	A	779,480	A	973,524	A	482,882	A	328,188	A
2,779,994	A	234,495	A	748,974	A	956,451	A	467,791	A	372,283	A
1,809,143	A	144,404	A	383,778	A	676,609	A	355,947	A	248,406	A
895,260	A	60,980	A	201,452	A	270,835	A	230,523	A	131,471	A
	U		U		U		U		U		U

5.4 Dishwasher

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a dishwasher								
Yes	4,620,076	A	889,005	A	560,288	A	80,646	A
No	2,571,464	A	832,412	A	1,500,969	A	114,531	A
Type of dishwasher								
Compact (exterior width less than 56 cm / 22 in.)	99,854	M		U		U		U
Standard (exterior width greater than or equal to 56 cm / 22 in.)	4,520,222	A	856,488	A	492,092	A	79,118	A
Age of dishwasher								
3 years old or less	1,157,834	A	231,668	A	170,431	A		U
4 to 5 years old	767,979	A	132,844	M		U		U
6 to 10 years old	1,331,748	A	300,433	A	109,392	M		U
11 to 15 years old	709,433	A	107,325	M	111,158	M		U
16 to 20 years old	421,613	A		U		U		U
21 years old or more	187,655	A		U		U		U
Don't know		U		U		U		U
Loads of dishes per week								
Don't use the dishwasher	216,058	A		U		U		U
1 to 2	1,353,291	A	325,443	A	270,557	A		U
3 to 5	1,941,069	A	314,435	A	220,967	A		U
More than 5	1,100,017	A	188,045	M		U		U
Don't know		U		U		U		U
Dish-drying habits with dishwasher								
Heat on (hot air)	2,489,952	A	465,884	A	274,118	A	41,842	M
Heat off (door closed)	1,335,842	A	250,859	A	154,134	M		U
Door open (dishes dry naturally)	761,132	A	167,098	A	128,647	M		U
Don't know		U		U		U		U
Dish-rinsing habits before using dishwasher								
Most of the time	2,788,704	A	551,484	A	418,340	A		U
Sometimes	894,494	A	176,399	A	96,069	M		U
Rarely	387,047	A		U		U		U
Never	542,653	A		U		U		U
Don't know		U		U		U		U
Households with an ENERGY STAR® dishwasher								
Yes	819,621	A	142,456	M	90,859	M		U
No	227,668	A		U		U		U
Don't know	154,361	A		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.4

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
6,150,014 A	393,361 A	1,615,228 A	2,123,372 A	1,092,467 A	925,586 A
5,019,375 A	506,981 A	1,369,016 A	1,758,659 A	810,296 A	574,423 A
202,093 A	U	U	U	U	73,294 M
5,947,920 A	381,866 A	1,582,718 A	2,058,112 A	1,072,933 A	852,292 A
1,578,524 A	90,052 A	356,342 A	614,040 A	279,811 A	238,280 A
974,589 A	53,465 A	323,804 A	338,444 A	140,133 A	118,742 A
1,770,488 A	133,588 A	405,891 A	604,542 A	335,099 A	291,368 A
936,352 A	64,838 A	248,496 A	296,646 A	189,286 A	137,087 A
576,641 A	34,290 A	179,753 A	191,933 A	83,616 M	87,049 M
252,201 A	U	95,758 M	U	U	U
61,218 M	U	U	U	U	U
298,392 A	U	118,320 A	U	U	U
1,979,316 A	120,878 A	608,205 A	679,791 A	330,176 A	240,265 A
2,516,795 A	153,255 A	626,732 A	863,366 A	476,787 A	396,655 A
1,345,869 A	101,497 A	261,972 A	484,971 A	248,544 A	248,884 A
U	U	U	U	U	U
3,271,795 A	214,411 A	936,041 A	1,041,410 A	607,024 A	472,909 A
1,772,668 A	107,039 A	428,984 A	666,255 A	327,133 A	243,256 A
1,063,848 A	70,471 A	244,715 A	393,483 A	152,977 A	202,203 A
U	U	U	U	U	U
3,807,449 A	213,167 A	1,212,786 A	1,248,699 A	566,991 A	565,807 A
1,181,834 A	101,982 A	151,218 A	495,049 A	217,083 A	216,503 A
467,341 A	34,118 A	U	148,741 A	135,501 A	68,503 M
686,211 A	44,094 A	170,746 A	229,351 A	170,850 A	71,169 A
U	U	U	U	U	U
1,067,036 A	62,086 A	228,002 A	410,740 A	194,732 A	171,476 A
345,114 A	U	81,897 M	147,962 M	U	U
227,593 A	U	U	U	U	U

5.4 Dishwasher

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Condition of previous dishwasher when replaced								
Still working	958,995	A	104,018	M		U		U
Not working	711,622	A		U		U		U
This is the original/first dishwasher	1,530,840	A	325,950	A	203,243	A		U
Don't know		U		U		U		U
Age of previous dishwasher when replaced								
5 years old or less	78,987	M		U		U		U
6 to 10 years old	154,724	A		U		U		U
11 to 15 years old	206,158	A		U		U		U
16 to 20 years old	140,685	A		U		U		U
21 years old or more	72,948	M		U		U		U
Don't know	64,187	M		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.4 (cont. 2/2)

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
1,168,351	A	65,860	A	470,460	A	393,516	A	145,677	A	92,837	A
790,736	A	57,332	A	231,564	A	308,407	A	133,857	A	59,576	M
2,083,712	A	188,682	A	563,394	A	796,069	A	297,549	A	238,018	A
	U		U		U		U		U		U
94,858	M		U		U		U		U		U
161,268	A		U		U		U		U		U
229,896	A		U		U		U	46,445	M		U
161,583	A		U		U		U		U		U
85,011	M		U		U		U		U		U
66,176	M		U		U		U		U		U

5.5 Freezer

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a freezer								
Yes	5,257,205	A	882,487	A	545,515	A	129,585	A
No	1,934,335	A	838,929	A	1,515,742	A	65,591	M
Number of freezers								
0	1,934,335	A	838,929	A	1,515,742	A	65,591	M
1	4,581,878	A	836,583	A	537,462	A	120,381	A
2	603,303	A		U		U		U
3 or more	72,025	M		U		U		U
Age of the main freezer								
3 years old or less	622,328	A	181,957	A	88,531	M		U
4 to 5 years old	390,780	A		U		U		U
6 to 10 years old	1,171,826	A	255,673	A	195,732	A		U
11 to 15 years old	969,906	A	141,702	M	97,355	M		U
16 to 20 years old	889,650	A	148,004	M		U		U
21 years old or more	1,185,301	A		U		U		U
Don't know		U		U		U		U
Size of the main freezer								
Very small (less than 7.0 cubic feet)	290,736	A	111,483	A	96,866	M		U
Small (7.1 to 13.9 cubic feet)	1,532,578	A	389,866	A	284,697	A	61,837	A
Medium (14.0 to 17.9 cubic feet)	1,971,501	A	251,511	A	135,527	M	48,555	M
Large (18.0 to 22.9 cubic feet)	1,116,697	A	107,001	M		U		U
Very large (23 cubic feet or more)	338,827	A		U		U		U
Don't know		U		U		U		U
Type of main freezer								
A chest type (top opening)	4,488,009	A	729,735	A	477,397	A	122,920	A
An upright type (front opening)	765,248	A	152,752	A		U		U
Don't know		U		U		U		U
Type of defrost for main freezer								
Automatic defrost	1,521,262	A	287,199	A	165,343	M		U
Manual defrost	3,714,360	A	591,994	A	378,816	A	83,106	A
Don't know		U		U		U		U
Households with an ENERGY STAR® freezer								
Yes	417,378	A	126,491	A		U		U
No	148,626	A		U		U		U
Don't know	83,738	M		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.5

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
6,814,793	A	621,292	A	1,504,832	A	2,419,388	A	1,397,774	A	871,507	A
4,354,596	A	279,050	A	1,479,412	A	1,462,643	A	504,989	A	628,502	A
4,354,596	A	279,050	A	1,479,412	A	1,462,643	A	504,989	A	628,502	A
6,076,304	A	545,366	A	1,375,597	A	2,261,756	A	1,159,258	A	734,327	A
663,583	A	69,595	A	113,287	M	149,761	A	200,497	A	130,443	M
74,905	M		U		U		U		U		U
925,415	A	88,714	A	168,278	A	341,308	A	205,029	A	122,086	A
527,375	A	48,780	A	123,636	A	195,009	A	116,396	A		U
1,655,277	A	185,605	A	329,367	A	579,710	A	309,570	A	251,027	A
1,240,549	A	87,195	A	314,825	A	459,618	A	259,656	A	119,255	A
1,135,191	A	94,194	A	279,660	A	388,234	A	185,871	A	187,231	A
1,298,542	A	114,222	A	284,322	A	443,682	A	315,177	A	141,140	A
	U		U		U		U		U		U
503,789	A	40,001	M	122,455	M	157,837	A	113,847	A	69,650	M
2,268,978	A	200,058	A	494,397	A	856,658	A	410,752	A	307,113	A
2,407,093	A	239,495	A	510,637	A	841,683	A	515,255	A	300,024	A
1,259,861	A	115,245	A	261,813	A	448,982	A	277,423	A	156,398	A
368,205	A		U		U		U	77,507	M		U
	U		U		U		U		U		U
5,818,060	A	565,950	A	1,232,742	A	2,008,122	A	1,256,892	A	754,355	A
992,784	A	55,343	A	272,090	A	411,266	A	136,933	A	117,152	M
	U		U		U		U		U		U
2,020,283	A	168,126	A	447,044	A	798,604	A	371,688	A	234,821	A
4,768,277	A	453,166	A	1,051,443	A	1,617,679	A	1,015,957	A	630,031	A
	U		U		U		U		U		U
610,668	A	55,644	A	80,567	M	237,151	A	144,195	A	93,112	A
229,416	A		U		U		U		U		U
117,775	A		U		U		U		U		U

5.5 Freezer

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Condition of previous freezer when replaced								
Still working	996,327	A	162,173	A	92,845	M		U
Not working	627,267	A		U		U		U
This is the original/first freezer	3,354,634	A	618,947	A	381,119	A	76,703	A
Don't know		U		U		U		U
Age of previous freezer when replaced								
10 years old or less	90,810	M		U		U		U
11 to 15 years old	87,372	M		U		U		U
16 to 20 years old	145,186	A		U		U		U
21 to 25 years old	106,914	M		U		U		U
26 years or more	126,841	A		U		U		U
Don't know	91,663	M		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
1,273,499	A	135,952	A	267,721	A	420,169	A	269,589	A	180,068	A
759,476	A	83,294	A	174,615	M	294,815	A	146,968	A	59,784	M
4,431,404	A	373,907	A	1,005,690	A	1,592,536	A	905,986	A	553,285	A
	U		U		U		U		U		U
113,376	M		U		U		U		U		U
103,588	M		U		U		U		U		U
185,620	A		U		U		U		U		U
115,271	A		U		U		U		U		U
164,715	A		U		U		U		U		U
100,413	M		U		U		U		U		U

5.6 Clothes washer

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a clothes washer								
Yes	7,101,939	A	1,592,184	A	982,550	A	181,865	A
No	89,601	M	129,232	M	1,072,972	A		U
Not stated		U		U		U		U
Type of clothes washer								
Automatic washer	6,950,357	A	1,544,732	A	940,398	A	176,146	A
Washer/dryer combination	121,440	A		U		U		U
Other		U		U		U		U
Not stated		U		U		U		U
Type of loading for clothes washer								
Front loading	841,791	A	173,524	A	108,245	M		U
Top loading	6,260,148	A	1,418,660	A	874,305	A	172,599	A
Not stated		U		U		U		U
Age of clothes washer								
3 years old or less	1,587,567	A	451,995	A	242,465	A		U
4 to 5 years old	1,142,567	A	229,484	A	109,995	A		U
6 to 10 years old	2,041,215	A	478,208	A	288,148	A	54,984	M
11 to 15 years old	1,265,876	A	195,988	A	175,240	A		U
16 to 20 years old	645,353	A	133,927	M	85,097	M		U
21 years old or more	368,236	A		U		U		U
Don't know		U		U		U		U
Size of clothes washer								
Compact (less than 45 litres / 10 gallons)	117,193	A		U	141,450	M		U
Standard (greater than or equal to 45 litres / 10 gallons)	6,982,398	A	1,537,632	A	841,100	A	176,782	A
Not stated		U		U		U		U
Water temperature used for washing in clothes washer								
Hot	309,432	A		U		U		U
Warm	4,313,506	A	927,120	A	448,020	A	97,163	A
Cold	2,418,268	A	584,505	A	510,861	A	67,638	M
Don't know		U		U		U		U
Water temperature used for rinsing in clothes washer								
Hot		U		U		U		U
Warm	1,256,366	A	354,868	A	168,793	A		U
Cold	5,723,067	A	1,203,455	A	802,644	A	145,730	A
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.6

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
9,858,538	A	790,874	A	2,702,190	A	3,474,241	A	1,687,588	A	1,203,645	A
1,305,116	A	109,468	A	282,054	A	407,790	A	209,439	A	296,364	A
	U		U		U		U		U		U
9,611,633	A	758,069	A	2,688,308	A	3,370,319	A	1,643,645	A	1,151,293	A
213,107	A		U		U		U		U		U
	U		U		U		U		U		U
	U		U		U		U		U		U
1,132,826	A	33,505	M	428,942	A	395,671	A	168,695	A	106,015	A
8,725,711	A	757,369	A	2,273,249	A	3,078,570	A	1,518,893	A	1,097,630	A
	U		U		U		U		U		U
2,308,483	A	163,577	A	569,825	A	960,929	A	376,701	A	237,450	A
1,507,818	A	132,370	A	461,776	A	508,225	A	236,981	A	168,467	A
2,862,555	A	247,987	A	716,042	A	976,099	A	514,173	A	408,254	A
1,679,794	A	131,897	A	550,189	A	523,924	A	274,506	A	199,278	A
886,321	A	75,683	A	248,532	A	267,152	A	160,094	A	134,860	M
512,013	A	32,802	M	141,330	A	199,963	A	95,477	M		U
107,289	M		U		U		U		U		U
318,278	A	47,787	M		U		U		U	76,172	M
9,537,912	A	743,087	A	2,606,430	A	3,407,133	A	1,653,789	A	1,127,473	A
	U		U		U		U		U		U
414,468	A	32,716	M		U	146,630	M	116,911	A		U
5,785,809	A	390,534	A	1,301,180	A	2,228,346	A	1,152,331	A	713,417	A
3,581,272	A	366,265	A	1,339,510	A	1,049,969	A	400,152	A	425,375	A
	U		U		U		U		U		U
90,828	M		U		U		U		U		U
1,809,863	A	102,482	A	401,421	A	712,514	A	364,368	A	229,077	A
7,874,896	A	682,892	A	2,277,855	A	2,675,483	A	1,284,590	A	954,076	A
	U		U		U		U		U		U

5.6 Clothes washer

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Use of clothes washer in winter								
Don't use the washer		U		U		U		U
1 to 2 loads per week	1,571,736	A	446,249	A	331,327	A	61,171	M
3 to 5 loads per week	2,782,651	A	687,836	A	422,835	A	50,156	M
More than 5 loads per week	2,679,070	A	449,570	A	219,388	A	65,790	A
Don't know		U		U		U		U
Use of clothes washer in summer								
Don't use the washer		U		U		U		U
1 to 2 loads per week	1,519,945	A	393,963	A	314,507	A	72,095	M
3 to 5 loads per week	2,870,882	A	736,361	A	455,531	A	44,093	M
More than 5 loads per week	2,656,529	A	449,706	A	208,043	A	65,677	A
Don't know		U		U		U		U
Households with an ENERGY STAR® clothes washer								
Yes	1,212,679	A	285,668	A	156,317	A		U
No	260,361	A	106,372	M		U		U
Don't know	165,652	A		U		U		U
Condition of previous clothes washer when replaced								
Still working	1,909,521	A	319,827	A	278,758	A		U
Not working	2,435,900	A	298,682	A	230,010	A		U
This is the original/first clothes washer	1,514,621	A	462,657	A	320,837	A		U
Don't know		U		U		U		U
Age of previous clothes washer when replaced								
5 years old or less	168,646	A		U		U		U
6 to 10 years old	323,521	A		U		U		U
11 to 15 years old	573,440	A	76,798	M		U		U
16 to 20 years old	720,022	A		U		U		U
21 years old or more	524,890	A		U		U		U
Don't know	192,227	A		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.6 (cont. 2/2)

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
76,520 M	U	U	U	U	U
2,410,482 A	183,398 A	637,072 A	903,980 A	362,779 A	323,253 A
3,943,478 A	261,178 A	1,134,664 A	1,382,529 A	706,556 A	458,551 A
3,413,818 A	336,174 A	919,740 A	1,139,837 A	606,424 A	411,642 A
U	U	U	U	U	U
U	U	U	U	U	U
2,300,510 A	175,441 A	628,402 A	831,189 A	372,724 A	292,755 A
4,106,866 A	283,603 A	1,150,945 A	1,492,671 A	671,956 A	507,693 A
3,379,955 A	329,178 A	913,094 A	1,110,733 A	633,984 A	392,965 A
U	U	U	U	U	U
1,677,366 A	102,714 A	389,288 A	714,876 A	279,479 A	191,009 A
429,637 A	34,428 A	126,992 A	175,912 A	68,887 A	U
308,769 A	U	U	108,089 M	U	U
2,545,040 A	201,060 A	1,034,207 A	784,994 A	362,985 A	161,793 A
2,998,313 A	308,023 A	939,038 A	1,131,286 A	399,776 A	220,190 A
2,338,857 A	192,508 A	605,031 A	801,300 A	479,375 A	260,643 A
95,832 M	U	U	U	U	U
206,556 A	U	U	U	U	U
395,507 A	52,732 A	121,817 M	156,817 M	33,751 M	U
728,585 A	70,868 A	243,508 A	280,465 A	85,135 M	U
859,566 A	87,456 A	263,232 A	323,503 A	138,985 A	U
632,840 A	59,728 A	207,513 A	214,485 A	102,723 A	48,392 M
271,091 A	U	U	U	U	U

5.7 Clothes dryer

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a clothes dryer								
Yes	6,709,755	A	1,508,808	A	880,539	A	177,020	A
No	481,785	A	212,608	A	1,180,718	A		U
Households with condensing clothes dryer not vented to the outside								
Yes	725,628	A	205,450	A	186,888	A		U
No	5,970,305	A	1,300,131	A	690,404	A	159,865	A
Don't know		U		U		U		U
Households with moisture detector in clothes dryer								
Yes	2,246,262	A	350,786	A	166,157	A	29,727	M
No	4,207,879	A	1,082,191	A	635,060	A	141,382	A
Don't know	255,614	A		U		U		U
Age of clothes dryer								
3 years old or less	1,370,379	A	361,462	A	197,688	A		U
4 to 5 years old	931,448	A	220,513	A	108,523	M		U
6 to 10 years old	1,853,219	A	422,939	A	232,492	A	52,813	M
11 to 15 years old	1,310,464	A	237,881	A	142,236	M		U
16 to 20 years old	717,995	A	133,864	A	106,811	M		U
21 years old or more	479,499	A		U		U		U
Don't know		U		U		U		U
Size of clothes dryer								
Compact (less than 125-litre/28-gallon capacity)	91,683	A		U	105,011	M		U
Standard (greater than or equal to 125-litre/28-gallon capacity)	6,618,072	A	1,453,352	A	775,528	A	174,664	A
Use of clothes dryer in winter								
Don't use it	127,994	A		U		U		U
1 to 2 loads per week	1,714,704	A	474,819	A	356,303	A	70,027	M
3 to 5 loads per week	2,607,121	A	611,628	A	310,911	A	46,157	M
More than 5 loads per week	2,242,924	A	385,259	A	197,604	A	58,227	A
Don't know		U		U		U		U
Use of clothes dryer in summer								
Don't use it	1,019,198	A	231,944	A	168,144	A		U
1 to 2 loads per week	2,134,400	A	559,360	A	342,668	A	77,157	A
3 to 5 loads per week	2,105,246	A	517,374	A	254,581	A	40,489	M
More than 5 loads per week	1,432,912	A	200,130	A	115,145	M		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.7

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
9,276,122 A	749,816 A	2,509,365 A	3,209,104 A	1,671,252 A	1,136,585 A
1,893,267 A	150,526 A	474,879 A	672,927 A	231,511 A	363,424 A
1,135,120 A	77,683 A	342,548 A	372,013 A	201,726 A	141,151 A
8,120,704 A	669,960 A	2,166,817 A	2,826,102 A	1,467,308 A	990,517 A
U	U	U	U	U	U
2,792,932 A	181,112 A	632,971 A	1,089,968 A	531,561 A	357,320 A
6,066,512 A	543,534 A	1,738,045 A	1,965,632 A	1,077,316 A	741,985 A
416,677 A	U	138,349 M	153,503 A	U	U
1,956,534 A	136,387 A	464,313 A	752,207 A	406,252 A	197,375 A
1,286,341 A	115,513 A	406,653 A	420,448 A	209,487 A	134,240 A
2,561,464 A	186,770 A	594,976 A	935,752 A	477,773 A	366,193 A
1,732,315 A	157,737 A	515,759 A	559,491 A	288,221 A	211,107 A
977,151 A	90,964 A	305,050 A	294,303 A	146,943 A	139,891 M
665,673 A	49,904 A	209,149 A	214,767 A	116,969 A	74,884 M
96,644 M	U	U	U	U	U
254,505 A	U	U	U	U	70,559 M
9,021,617 A	722,046 A	2,426,462 A	3,161,822 A	1,645,261 A	1,066,025 A
182,795 A	U	U	U	U	U
2,615,852 A	174,192 A	797,257 A	940,433 A	390,294 A	313,676 A
3,575,817 A	258,690 A	978,667 A	1,218,327 A	689,948 A	430,184 A
2,884,014 A	300,479 A	664,913 A	989,890 A	554,613 A	374,118 A
U	U	U	U	U	U
1,443,140 A	205,634 A	693,999 A	384,975 A	82,569 A	75,963 M
3,113,585 A	234,514 A	985,972 A	1,065,858 A	464,967 A	362,275 A
2,917,691 A	182,806 A	588,945 A	1,158,863 A	605,988 A	381,089 A
1,783,706 A	126,863 A	237,445 A	586,540 A	515,601 A	317,257 A
U	U	U	U	U	U

5.7 Clothes dryer

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home
Condition of previous clothes dryer when replaced							
Still working	2,029,485	A	319,270	A	301,860	A	U
Not working	1,575,950	A	150,349	M	126,922	M	U
This is the original/first clothes dryer	1,933,703	A	521,881	A	293,570	A	U
Don't know		U		U		U	U
Age of previous clothes dryer when replaced							
5 years old or less	112,794	M		U		U	U
6 to 10 years old	139,308	A		U		U	U
11 to 15 years old	416,435	A		U		U	U
16 to 20 years old	386,880	A		U		U	U
21 years old or more	410,668	A		U		U	U
Don't know	168,733	A		U		U	U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.7 (cont. 2/2)

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
2,690,364	A	161,452	A	1,176,339	A	806,514	A	371,455	A	174,604	A
1,872,122	A	233,787	A	497,417	A	725,864	A	287,180	A	127,874	A
2,797,056	A	261,915	A	715,684	A	952,916	A	565,623	A	300,917	A
81,165	M		U		U		U		U		U
133,200	A		U		U		U		U		U
161,520	A		U		U		U		U		U
492,735	A	50,756	A	136,541	M	189,506	A	74,241	M		U
450,082	A	63,695	A	119,573	M	164,311	M	86,270	A		U
477,248	A	56,048	A	127,091	M	183,843	A	70,968	A		U
238,502	A		U		U		U		U		U

5.8 Personal computer

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a personal computer								
Yes	5,104,116	A	1,194,743	A	1,009,692	A	112,417	A
No	2,087,424	A	524,630	A	1,051,564	A	82,759	A
Don't know		U		U		U		U
Number of personal computers								
0	2,087,424	A	524,630	A	1,051,564	A	82,759	A
1	3,669,306	A	948,377	A	819,051	A	99,938	A
2 or more	1,434,810	A	246,365	A	190,642	A		U
Don't know		U		U		U		U
Time main personal computer is turned on per week								
0	110,637	M		U		U		U
1 to 24 hours	2,484,079	A	654,664	A	495,017	A	60,260	A
25 to 72 hours	990,797	A	199,797	A	248,785	A		U
73 to 168 hours	1,487,508	A	301,648	A	245,354	A		U
Don't know		U		U		U		U
Time main personal computer is used per week (including time used for downloading)								
0		U		U		U		U
1 to 24 hours	3,598,300	A	887,879	A	661,045	A	76,865	A
25 to 72 hours	1,240,368	A	253,942	A	272,644	A		U
73 to 168 hours	94,698	M		U		U		U
Don't know		U		U		U		U
Age of most frequently used personal computer								
3 years old or less	2,914,676	A	680,006	A	592,261	A	59,754	M
4 to 5 years old	1,270,066	A	314,797	A	230,148	A		U
6 to 10 years old	823,857	A	184,272	A	154,000	A		U
11 years old or more	70,655	M		U		U		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.8

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
7,420,968	A	539,920	A	1,816,515	A	2,776,977	A	1,242,639	A	1,044,917	A
3,746,377	A	360,422	A	1,165,685	A	1,105,054	A	660,124	A	455,092	A
	U		U		U		U		U		U
3,746,377	A	360,422	A	1,165,685	A	1,105,054	A	660,124	A	455,092	A
5,536,672	A	450,735	A	1,386,326	A	2,012,259	A	973,505	A	713,847	A
1,884,296	A	89,185	A	430,189	A	764,718	A	269,134	A	331,070	A
	U		U		U		U		U		U
159,865	A		U		U		U		U		U
3,694,019	A	233,464	A	977,983	A	1,516,478	A	534,218	A	431,876	A
1,463,979	A	107,810	A	345,524	A	541,580	A	239,018	A	230,048	A
2,059,593	A	181,192	A	430,090	A	649,072	A	432,970	A	366,269	A
	U		U		U		U		U		U
	U		U		U		U		U		U
5,224,088	A	362,755	A	1,309,293	A	1,997,462	A	888,084	A	666,493	A
1,798,707	A	142,801	A	386,876	A	642,129	A	291,897	A	335,005	A
157,346	A		U		U		U		U		U
	U		U		U		U		U		U
4,246,697	A	294,199	A	1,041,955	A	1,593,501	A	689,294	A	627,748	A
1,837,870	A	113,589	A	467,513	A	694,607	A	344,459	A	217,702	A
1,187,679	A	119,782	A	281,900	A	420,540	A	183,299	A	182,157	A
107,955	A		U		U		U		U		U
	U		U		U		U		U		U

5.9 Television

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a television set								
Yes	7,134,663	A	1,699,674	A	2,010,759	A	193,192	A
No		U		U		U		U
Number of television sets								
1	1,874,367	A	630,616	A	1,288,296	A	94,491	A
2	3,075,656	A	708,824	A	620,571	A	65,233	A
3 or more	2,184,640	A	360,235	A	101,892	A		U
Time main television set is turned on per week								
0		U		U		U		U
1 to 24 hours	2,793,354	A	711,153	A	845,561	A	66,980	A
25 to 72 hours	3,776,660	A	874,716	A	968,513	A	97,686	A
73 to 168 hours	543,512	A	110,362	M	196,685	A		U
Don't know		U		U		U		U
Age of main television set								
3 years old or less	2,228,134	A	530,002	A	514,044	A	73,912	A
4 to 5 years old	1,220,508	A	334,797	A	341,870	A		U
6 to 10 years old	2,194,351	A	518,758	A	710,131	A	50,285	M
11 to 15 years old	915,510	A	185,224	A	247,449	A		U
16 to 20 years old	397,779	A	96,073	M	130,451	M		U
21 years old or more	157,318	A		U		U		U
Don't know		U		U		U		U
Households with an ENERGY STAR® main television set								
Yes	1,068,487	A	232,656	A	168,325	A		U
No	668,615	A	201,724	A	238,071	A		U
Don't know	512,094	A	97,993	M	110,628	M		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.9

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
11,038,288 A	898,781 A	2,955,544 A	3,828,374 A	1,881,981 A	1,473,608 A
131,101 M	U	U	U	U	U
3,887,769 A	282,026 A	1,171,169 A	1,104,283 A	634,037 A	696,254 A
4,470,285 A	354,611 A	1,210,923 A	1,646,848 A	788,026 A	469,878 A
2,680,234 A	262,145 A	573,452 A	1,077,243 A	459,918 A	307,477 A
U	U	U	U	U	U
4,417,049 A	288,533 A	1,122,533 A	1,672,905 A	704,703 A	628,375 A
5,717,575 A	491,211 A	1,574,115 A	1,854,133 A	1,029,992 A	768,125 A
878,545 A	117,685 A	258,897 A	286,302 A	140,067 A	75,595 M
U	U	U	U	U	U
3,346,092 A	286,836 A	870,260 A	1,151,294 A	569,580 A	468,122 A
1,937,145 A	159,471 A	504,603 A	671,754 A	361,539 A	239,779 A
3,473,524 A	251,887 A	907,786 A	1,274,475 A	571,800 A	467,577 A
1,366,295 A	114,290 A	422,255 A	448,505 A	222,683 A	158,562 A
629,360 A	57,011 A	177,691 A	200,045 A	84,146 M	110,467 M
259,456 A	U	U	U	U	U
U	U	U	U	U	U
1,502,282 A	115,749 A	397,125 A	531,275 A	228,250 A	229,883 A
1,137,038 A	115,150 A	302,337 A	377,882 A	223,330 A	118,339 A
733,186 A	60,784 A	175,063 A	252,491 A	124,948 A	119,900 A

5.10 Video cassette recorder (VCR)

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a VCR								
Yes	6,123,334	A	1,396,086	A	1,563,851	A	174,042	A
No	1,068,206	A	325,330	A	497,406	A		U
Number of VCRs								
1	4,079,506	A	1,042,686	A	1,360,434	A	150,224	A
2	1,675,107	A	298,075	A	176,427	A		U
3 or more	368,722	A		U		U		U
Time main VCR is turned on per week								
0	1,140,842	A	198,338	A	269,572	A		U
1 to 24 hours	4,726,739	A	1,161,391	A	1,193,962	A	137,962	A
25 to 72 hours	172,650	A		U		U		U
73 to 168 hours	61,242	M		U		U		U
Don’t know		U		U		U		U
Age of the main VCR								
3 years old or less	1,942,085	A	478,297	A	641,761	A	55,914	A
4 to 5 years old	1,270,614	A	369,705	A	331,911	A		U
6 to 10 years old	2,082,882	A	408,255	A	424,645	A	62,450	M
11 to 15 years old	574,899	A	80,525	M	144,478	M		U
16 years old or more	231,509	A		U		U		U
Don’t know		U		U		U		U
Households with an ENERGY STAR® main VCR								
Yes	866,229	A	216,587	A	289,002	A		U
No	704,390	A	168,639	A	255,990	A		U
Don’t know	392,811	A	102,593	M	99,750	M		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 5.10

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
9,257,313 A	740,735 A	2,482,350 A	3,227,825 A	1,612,903 A	1,193,500 A
1,912,076 A	159,607 A	501,894 A	654,206 A	289,860 A	306,509 A
6,632,851 A	533,880 A	1,746,168 A	2,302,234 A	1,143,643 A	906,926 A
2,168,252 A	175,589 A	639,729 A	759,981 A	373,957 A	218,995 A
456,211 A	31,266 M	96,452 M	165,611 M	95,303 M	67,579 M
1,634,283 A	134,247 A	450,489 A	588,750 A	281,790 A	179,007 A
7,220,055 A	568,044 A	1,904,212 A	2,536,079 A	1,251,960 A	959,759 A
257,101 A	U	U	U	59,042 M	U
113,220 M	U	U	U	U	U
U	U	U	U	U	U
3,118,056 A	226,737 A	853,408 A	1,079,250 A	556,272 A	402,389 A
2,010,286 A	165,155 A	508,286 A	780,581 A	333,049 A	223,214 A
2,978,232 A	239,952 A	799,531 A	1,029,388 A	522,723 A	386,638 A
812,257 A	73,493 A	239,469 A	219,726 A	140,324 A	139,245 A
304,632 A	33,671 M	U	104,140 M	52,181 A	U
U	U	U	U	U	U
1,390,472 A	88,901 A	358,186 A	515,921 A	224,833 A	202,631 A
1,144,038 A	89,251 A	346,827 A	372,868 A	213,601 A	121,491 M
617,396 A	50,312 A	152,661 M	205,200 A	126,192 A	83,031 A

5.11 DVD player

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a DVD player (excluding video game systems that can play DVDs)								
Yes	4,157,710	A	945,712	A	782,741	A	78,419	A
No	3,033,830	A	775,704	A	1,278,516	A	116,757	A
Number of DVD players								
1	3,433,223	A	813,975	A	729,400	A	74,178	A
2 or more	722,132	A	131,736	A		U		U
Don't know		U		U		U		U
Time main DVD player is turned on per week								
0	424,803	A		U		U		U
1 to 3	2,342,083	A	450,246	A	385,028	A		U
4 to 5	670,709	A	269,339	A	145,899	M		U
6 hours or more	696,500	A	154,825	A	183,484	A		U
Don't know		U		U		U		U
Age of the main DVD player								
1 year or less	2,239,009	A	412,298	A	462,282	A	49,705	M
2 to 3 years old	1,512,603	A	439,825	A	267,056	A		U
4 to 5 years old	322,621	A		U		U		U
6 years old or more		U		U		U		U
Don't know		U		U		U		U
Households with an ENERGY STAR® main DVD player								
Yes	1,748,900	A	379,466	A	288,984	A		U
No	1,066,033	A	299,209	A	293,011	A		U
Don't know	946,137	A	173,449	A	147,342	A		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.11

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
5,964,582 A	401,791 A	1,521,009 A	2,165,421 A	1,071,598 A	804,763 A
5,204,807 A	498,551 A	1,463,235 A	1,716,610 A	831,165 A	695,246 A
5,050,776 A	349,399 A	1,363,687 A	1,786,407 A	871,479 A	679,805 A
911,451 A	52,392 A	157,322 A	376,659 A	200,119 A	124,959 A
U	U	U	U	U	U
563,360 A	46,886 A	172,947 A	200,648 A	67,385 M	75,494 M
3,210,623 A	201,167 A	851,429 A	1,177,650 A	560,728 A	419,648 A
1,106,553 A	65,478 A	256,640 A	465,372 A	196,921 A	122,143 A
1,054,380 A	86,840 A	231,444 A	311,828 A	239,920 A	184,347 A
U	U	U	U	U	U
3,163,294 A	276,736 A	854,555 A	1,018,124 A	579,785 A	434,093 A
2,245,236 A	102,054 A	488,023 A	934,202 A	406,482 A	314,475 A
445,441 A	U	163,737 M	153,797 M	62,637 M	U
101,152 M	U	U	U	U	U
U	U	U	U	U	U
2,445,705 A	157,657 A	562,963 A	925,942 A	448,012 A	351,131 A
1,687,512 A	122,475 A	455,312 A	559,670 A	360,819 A	189,236 A
1,284,771 A	98,659 A	324,302 A	474,991 A	178,618 A	208,201 A

5.12 Video game system

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a video game system requiring an electrical outlet								
Yes	2,134,900	A	488,069	A	287,734	A	61,451	M
No	5,056,640	A	1,233,347	A	1,773,523	A	133,725	A
Number of video game systems requiring an electrical outlet								
1	1,706,322	A	402,897	A	227,754	A	48,094	M
2 or more	428,238	A	85,172	M		U		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.12

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
2,972,154	A	260,327	A	719,116	A	1,087,299	A	540,560	A	364,852	A
8,197,235	A	640,015	A	2,265,128	A	2,794,732	A	1,362,203	A	1,135,157	A
2,385,067	A	185,041	A	602,746	A	881,796	A	424,284	A	291,200	A
586,747	A	74,947	A	116,370	A	205,503	A	116,275	A	73,652	M
	U		U		U		U		U		U

5.13 Satellite dish

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a satellite dish								
Yes	2,216,313	A	295,304	A	135,201	M	71,993	A
No	4,975,227	A	1,426,112	A	1,926,056	A	123,183	A
Number of satellite dishes								
1	2,098,318	A	257,541	A	135,201	M	69,735	A
2 or more	117,995	A		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.13

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
2,718,812	A	247,751	A	680,860	A	1,015,914	A	546,743	A	227,544	A
8,450,577	A	652,591	A	2,303,384	A	2,866,117	A	1,356,020	A	1,272,465	A
2,560,794	A	240,833	A	658,830	A	947,639	A	493,827	A	219,665	A
158,018	A		U		U		U		U		U

5.14 Stereo system

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a component stereo system								
Yes	4,456,035	A	1,035,762	A	961,949	A	106,674	A
No	2,732,778	A	685,654	A	1,099,307	A	87,786	A
Don't know		U		U		U		U
Number of component stereo systems								
0	2,732,778	A	685,654	A	1,099,307	A	87,786	A
1	3,624,243	A	821,839	A	898,717	A	97,281	A
2 or more	831,792	A	213,924	A		U		U
Don't know		U		U		U		U
Households with a compact/portable stereo								
Yes	4,529,061	A	973,753	A	1,084,207	A	89,971	A
No	2,662,479	A	747,663	A	977,050	A	105,205	A
Number of compact/portable stereos								
0	2,662,479	A	747,663	A	977,050	A	105,205	A
1	3,063,668	A	743,545	A	920,986	A	74,180	A
2 or more	1,465,393	A	230,208	A	163,221	A		U
Don't know		U		U		U		U
Use of the main stereo system per week								
0	407,387	A		U	129,321	M		U
1 to 5 hours	2,740,303	A	671,753	A	747,741	A	68,281	A
6 to 10 hours	1,174,989	A	290,088	A	280,911	A		U
11 to 20 hours	784,178	A	210,652	A	231,420	A		U
21 hours or more	1,135,527	A	259,428	A	318,883	A		U
Don't know		U		U		U		U
Age of main stereo system								
3 years old or less	1,933,847	A	498,784	A	523,066	A	30,886	M
4 to 5 years old	1,090,019	A	248,632	A	275,166	A		U
6 to 10 years old	1,662,829	A	440,558	A	553,509	A	47,100	M
11 to 15 years old	747,509	A	154,183	M	208,256	A		U
16 to 20 years old	455,415	A		U		U		U
21 years old or more	319,386	A		U		U		U
Don't know		U		U		U		U
Households with an ENERGY STAR® main stereo system								
Yes	722,400	A	170,690	A	150,060	A		U
No	753,606	A	213,052	A	283,969	A		U
Don't know	509,063	A	125,486	M	97,755	M		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.14

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
6,560,421	A	449,504	A	1,668,800	A	2,335,882	A	1,130,252	A	975,983	A
4,605,525	A	450,838	A	1,315,444	A	1,546,149	A	771,794	A	521,299	A
	U		U		U		U		U		U
4,605,525	A	450,838	A	1,315,444	A	1,546,149	A	771,794	A	521,299	A
5,442,080	A	395,551	A	1,460,697	A	1,852,070	A	898,037	A	835,725	A
1,118,341	A	53,952	A	208,102	A	483,812	A	232,215	A	140,259	A
	U		U		U		U		U		U
6,676,993	A	544,248	A	1,767,796	A	2,404,893	A	1,078,141	A	881,916	A
4,492,396	A	356,094	A	1,216,448	A	1,477,138	A	824,622	A	618,093	A
4,492,396	A	356,094	A	1,216,448	A	1,477,138	A	824,622	A	618,093	A
4,802,380	A	377,799	A	1,319,248	A	1,686,956	A	755,582	A	662,795	A
1,874,614	A	166,449	A	448,548	A	717,937	A	322,559	A	219,121	A
	U		U		U		U		U		U
620,373	A	79,601	A	134,800	A	211,172	A	109,817	M	84,982	M
4,228,078	A	311,020	A	1,211,999	A	1,478,419	A	671,065	A	555,575	A
1,766,005	A	107,060	A	454,153	A	691,476	A	306,618	A	206,699	A
1,253,500	A	86,846	A	343,262	A	436,146	A	199,245	A	188,001	A
1,745,645	A	140,236	A	476,436	A	554,752	A	280,885	A	293,335	A
	U		U		U		U		U		U
2,986,583	A	264,913	A	777,575	A	1,047,618	A	509,995	A	386,483	A
1,654,574	A	129,735	A	442,872	A	562,335	A	322,760	A	196,872	A
2,703,996	A	173,311	A	782,409	A	977,799	A	414,437	A	356,040	A
1,123,316	A	90,792	A	278,472	A	396,928	A	152,362	A	204,761	A
638,701	A	32,938	M	193,656	A	232,782	A	88,221	A	91,103	M
455,788	A	30,207	M	142,005	M	145,268	M	71,929	M	66,380	M
	U		U		U		U		U		U
1,053,125	A	70,058	A	303,902	A	340,885	A	193,227	A	145,053	A
1,265,844	A	130,534	A	341,342	A	475,997	A	178,268	A	139,702	A
737,998	A	68,039	A	139,225	A	252,949	A	148,326	A	129,459	M

5.15 Telephone and answering machine

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a telephone requiring electricity								
Yes	6,558,012	A	1,545,485	A	1,618,455	A	182,975	A
No	633,528	A	175,931	A	442,802	A		U
Number of telephones requiring electricity								
0	633,528	A	175,931	A	442,802	A		U
1	2,378,850	A	707,137	A	877,329	A	88,288	A
2 to 3	3,518,480	A	746,675	A	707,604	A	92,326	A
4 or more	660,683	A	91,673	M		U		U
Age of main telephone requiring electricity								
3 years old or less	3,518,711	A	893,975	A	820,406	A	122,779	A
4 to 5 years old	1,230,697	A	284,307	A	278,731	A		U
6 to 10 years old	1,335,012	A	307,615	A	369,899	A		U
11 to 15 years old	345,737	A		U	109,269	M		U
16 to 20 years old	88,731	M		U		U		U
21 years old or more		U		U		U		U
Don’t know		U		U		U		U
Households with an answering machine								
Yes	3,100,070	A	626,768	A	724,190	A	60,748	M
No	4,091,470	A	1,094,648	A	1,337,067	A	134,428	A
Number of answering machines								
0	4,091,470	A	1,094,648	A	1,337,067	A	134,428	A
1	3,006,913	A	607,978	A	714,514	A	60,748	M
2 or more	93,157	A		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.15

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
9,904,928	A	789,128	A	2,596,618	A	3,497,117	A	1,679,677	A	1,342,388	A
1,264,461	A	111,214	A	387,626	A	384,914	A	223,086	A	157,621	A
1,264,461	A	111,214	A	387,626	A	384,914	A	223,086	A	157,621	A
4,051,604	A	330,597	A	1,122,631	A	1,375,007	A	719,689	A	503,680	A
5,065,085	A	405,073	A	1,258,643	A	1,833,817	A	846,708	A	720,843	A
788,239	A	53,458	A	215,343	A	288,293	A	113,279	A	117,865	A
5,355,871	A	455,907	A	1,340,683	A	1,965,596	A	918,233	A	675,452	A
1,816,024	A	124,437	A	469,675	A	626,303	A	337,645	A	257,964	A
2,030,393	A	161,852	A	569,134	A	687,442	A	326,516	A	285,447	A
510,141	A		U	148,541	A	156,844	M	78,117	M	98,160	M
125,500	M		U		U		U		U		U
	U		U		U		U		U		U
	U		U		U		U		U		U
4,511,777	A	228,553	A	1,080,913	A	1,607,744	A	772,501	A	822,067	A
6,657,612	A	671,789	A	1,903,331	A	2,274,287	A	1,130,262	A	677,942	A
6,657,612	A	671,789	A	1,903,331	A	2,274,287	A	1,130,262	A	677,942	A
4,390,154	A	219,593	A	1,049,708	A	1,586,737	A	753,810	A	780,305	A
121,622	A		U		U		U		U		U

5.16 Water cooler

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a water cooler								
Yes	1,229,566	A	265,853	A	186,913	A		U
No	5,961,974	A	1,455,563	A	1,874,344	A	162,352	A

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 5.16

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
1,715,156	A	113,979	A	567,295	A	500,502	A	326,967	A	206,414	A
9,454,233	A	786,363	A	2,416,949	A	3,381,529	A	1,575,796	A	1,293,595	A

5.17 Swimming pool

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a swimming pool solely for the use of that household								
Yes	1,088,630	A		U		U		U
No	6,102,910	A	1,676,050	A		U	190,663	A
Households with a swimming pool for the use of the occupants in the building								
Yes		U		U	108,587	M		U
No		U		U	1,950,161	A		U
Don't know		U		U		U		U
Swimming pools with a pool heater								
Yes	212,230	A		U		U		U
No	876,400	A		U		U		U
Swimming pools with a programmable timer control on the filter								
Yes	392,270	A		U		U		U
No	683,016	A		U		U		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 5.17

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
1,138,509 A	35,400 M	594,994 A	419,465 A	U	U
7,969,623 A	751,878 A	1,427,028 A	3,042,601 A	1,635,208 A	1,112,908 A
108,587 M	U	U	U	U	U
1,950,161 A	113,063 A	904,613 A	411,401 A	196,238 A	324,846 A
U	U	U	U	U	U
219,361 A	U	64,446 M	101,766 M	U	U
919,149 A	31,443 M	530,548 A	317,699 A	U	U
395,690 A	U	237,542 A	133,650 A	U	U
729,474 A	33,789 M	357,452 A	282,661 A	U	U
U	U	U	U	U	U

SECTION 6

Hot Water

6.1 Hot water tank and appliances using hot water

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with a hot water tank								
Yes	7,035,780	A	1,661,185	A	1,392,605	A	195,176	A
No	155,400	A		U	660,195	A		U
Don't know		U		U		U		U
Source of energy used to heat the running water								
Electricity	3,254,709	A	771,321	A	1,196,153	A	159,387	A
Oil	278,978	A		U	87,274	M		U
Natural gas	3,565,861	A	902,724	A	744,833	A		U
Propane		U		U		U		U
Solar panel		U		U		U		U
Other source		U		U		U		U
No hot running water		U		U		U		U
Age of hot water tank								
5 years old or less	2,901,199	A	632,478	A	601,483	A	90,546	A
6 to 10 years old	2,046,000	A	388,838	A	308,746	A	46,729	M
11 to 15 years old	765,956	A	185,820	A	98,688	M		U
16 to 20 years old	395,606	A	97,345	M		U		U
21 to 25 years old	133,817	M		U		U		U
26 years old or more	471,656	A	147,200	M	159,884	A		U
Unsure, was there when moved in	225,252	A	119,458	M	92,817	M		U
Don't know	96,654	M		U		U		U
Condition of previous hot water tank when replaced								
Still working	1,244,467	A	197,368	A	251,830	A		U
Not working	3,026,204	A	525,316	A	569,205	A	56,471	M
This is the original/first hot water tank	2,428,070	A	742,520	A	343,858	A	70,123	A
Don't know	337,398	A	195,980	A	239,332	A		U
Age of previous hot water tank when replaced								
5 years old or less	393,371	A		U		U		U
6 to 10 years old	647,268	A	107,598	M	131,364	M		U
11 to 15 years old	566,790	A	125,928	M	109,901	M		U
16 to 20 years old	505,306	A	75,902	M	106,941	M		U
21 years old or more	531,741	A	101,452	M		U		U
Don't know	719,127	A	286,689	A	334,392	A		U
Hot water tank with insulation blanket								
Yes	833,518	A	187,193	A	309,459	A		U
No	2,606,902	A	597,826	A	985,187	A	125,237	A
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 6.1

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
10,284,746 A	738,361 A	2,804,592 A	3,688,585 A	1,782,278 A	1,270,930 A
875,827 A	160,623 A	179,652 A	185,988 M	120,485 M	229,079 A
U	U	U	U	U	U
5,381,570 A	639,466 A	2,698,393 A	1,095,610 A	344,377 A	603,723 A
402,641 A	238,268 A	U	U	U	U
5,240,206 A	U	205,381 A	2,636,400 A	1,534,288 A	861,672 A
67,871 M	U	U	U	U	U
U	U	U	U	U	U
U	U	U	U	U	U
U	U	U	U	U	U
4,225,706 A	363,358 A	1,195,989 A	1,455,128 A	649,013 A	562,219 A
2,790,313 A	161,088 A	844,051 A	941,249 A	524,270 A	319,655 A
1,061,848 A	70,320 A	227,084 A	468,135 A	163,773 A	132,537 A
546,201 A	34,709 M	96,033 M	225,517 A	143,840 A	46,103 M
197,217 A	U	U	U	U	U
797,786 A	55,503 M	234,808 A	259,702 A	126,334 A	121,440 A
453,648 A	U	108,022 M	176,093 A	100,632 M	U
224,005 A	U	U	U	U	U
1,736,407 A	99,144 A	442,468 A	790,412 A	224,323 A	180,061 A
4,177,196 A	374,367 A	1,383,488 A	1,265,810 A	624,765 A	528,765 A
3,584,571 A	226,720 A	757,693 A	1,350,366 A	803,968 A	445,824 A
798,551 A	39,489 M	220,943 A	289,455 A	129,222 A	119,443 A
446,213 A	54,776 A	161,969 A	108,482 M	66,806 M	U
894,867 A	106,140 A	295,492 A	225,082 A	116,636 A	151,517 A
813,212 A	62,518 A	308,372 A	226,875 A	101,809 A	113,638 A
696,432 A	51,072 A	271,007 A	185,341 A	117,158 A	71,855 A
756,932 A	54,716 A	195,918 A	284,119 A	134,947 A	87,234 M
1,368,091 A	84,633 A	371,674 A	525,366 A	216,633 A	169,785 A
1,364,320 A	107,344 A	718,301 A	292,187 A	U	207,709 A
4,315,153 A	613,852 A	1,965,966 A	915,042 A	377,517 A	442,777 A
116,625 M	U	U	U	U	U

6.1 Hot water tank and appliances using hot water

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households that added insulation blanket around hot water tank in 2003								
Yes	106,801	A		U		U		U
No	716,444	A	152,475	A	246,255	A		U
Don't know		U		U		U		U
Households with add-on insulation around hot water pipes								
Yes	2,367,572	A	517,886	A	279,200	A	82,416	A
No	4,479,156	A	1,073,153	A	1,005,473	A	108,026	A
Don't know	189,412	A	70,146	M	119,551	M		U
Households that added insulation around hot water pipes in 2003								
Yes	327,009	A	90,114	M		U		U
No	2,034,314	A	427,771	A	227,484	A	57,673	M
Don't know	195,661	A	70,146	M	123,647	M		U
Households with a water-saving showerhead								
Yes	4,151,668	A	933,764	A	819,768	A	90,947	A
No	2,972,859	A	775,829	A	1,199,023	A	104,229	A
Don't know	67,012	M		U		U		U
Households with tap attachments to reduce water consumption								
Yes	3,599,596	A	825,570	A	635,815	A	78,075	A
No	3,577,828	A	887,953	A	1,409,702	A	117,101	A
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
204,364 A	U	U	U	U	65,483 M
1,142,735 A	88,972 A	637,301 A	250,885 A	U	140,534 A
133,845 M	U	U	U	U	U
3,247,074 A	222,929 A	824,246 A	1,457,618 A	380,938 A	361,344 A
6,665,809 A	499,881 A	1,871,906 A	2,074,517 A	1,363,246 A	856,260 A
383,842 A	U	108,441 A	163,908 M	U	U
489,076 A	34,453 A	U	264,188 A	U	83,285 A
2,747,242 A	187,737 A	740,684 A	1,187,508 A	354,945 A	276,368 A
394,599 A	U	108,441 A	169,829 M	U	U
5,996,147 A	462,626 A	1,538,878 A	2,368,228 A	829,965 A	796,450 A
5,051,941 A	429,526 A	1,413,726 A	1,468,718 A	1,051,041 A	688,929 A
121,301 M	U	U	U	U	U
5,139,056 A	393,123 A	1,089,689 A	2,036,559 A	837,023 A	782,662 A
5,992,585 A	506,357 A	1,876,553 A	1,833,407 A	1,058,921 A	717,347 A
U	U	U	U	U	U

SECTION 7

Lighting

7.1 Light bulbs

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with ordinary light bulbs								
Yes	7,143,078	A	1,709,046	A	2,045,685	A	193,603	A
No		U		U		U		U
Don't know		U		U		U		U
Number of ordinary light bulbs								
0		U		U		U		U
1 to 10	1,170,115	A	485,030	A	1,161,370	A	61,179	M
11 to 20	2,530,081	A	665,728	A	780,881	A	105,961	A
21 to 30	1,830,868	A	356,073	A		U		U
31 or more	1,612,014	A	202,214	A		U		U
Don't know		U		U		U		U
Households with halogen light bulbs								
Yes	3,669,088	A	792,258	A	815,614	A	56,885	M
No	3,510,212	A	929,158	A	1,245,643	A	138,291	A
Don't know		U		U		U		U
Number of halogen light bulbs								
0	3,510,212	A	929,158	A	1,245,643	A	138,291	A
1 to 5 bulbs	2,423,566	A	586,094	A	687,299	A	46,781	M
6 bulbs or more	1,245,522	A	206,164	A	128,315	M		U
Don't know		U		U		U		U
Households with compact fluorescent lights								
Yes	2,561,402	A	556,440	A	360,517	A	74,827	M
No	4,625,860	A	1,164,976	A	1,700,740	A	120,349	A
Don't know		U		U		U		U
Number of compact fluorescent lights used								
0	4,625,860	A	1,164,976	A	1,700,740	A	120,349	A
1 to 5 bulbs	1,861,941	A	438,506	A	300,521	A	67,586	M
6 bulbs or more	699,461	A	117,934	M		U		U
Don't know		U		U		U		U
Households with fluorescent lights (excluding compact fluorescent lights)								
Yes	4,742,501	A	845,368	A	777,511	A	87,228	A
No	2,444,610	A	875,027	A	1,283,746	A	107,948	A
Don't know		U		U		U		U
Number of fluorescent lights (excluding compact fluorescent lights)								
0	2,444,610	A	875,027	A	1,283,746	A	107,948	A
1 to 5 bulbs	3,522,829	A	702,792	A	737,697	A	79,678	A
6 bulbs or more	1,219,671	A	142,576	M		U		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 7.1

BY REGION

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
11,091,412 A	897,199 A	2,961,177 A	3,854,770 A	1,895,796 A	1,482,469 A
64,971 M	U	U	U	U	U
U	U	U	U	U	U
64,971 M	U	U	U	U	U
2,877,694 A	172,000 A	1,015,902 A	844,065 A	428,763 A	416,964 A
4,082,652 A	377,546 A	1,146,521 A	1,335,649 A	712,454 A	510,481 A
2,297,404 A	201,238 A	478,709 A	906,229 A	456,024 A	255,204 A
1,833,663 A	146,415 A	320,045 A	768,828 A	298,555 A	299,820 A
U	U	U	U	U	U
5,333,845 A	272,028 A	1,745,404 A	1,735,814 A	798,929 A	781,670 A
5,823,304 A	628,314 A	1,237,401 A	2,135,416 A	1,103,834 A	718,339 A
U	U	U	U	U	U
5,823,304 A	628,314 A	1,237,401 A	2,135,416 A	1,103,834 A	718,339 A
3,743,739 A	221,160 A	1,155,712 A	1,183,529 A	636,600 A	546,738 A
1,590,106 A	50,868 A	589,692 A	552,285 A	162,328 A	234,932 A
U	U	U	U	U	U
3,553,186 A	199,082 A	721,815 A	1,274,459 A	657,361 A	700,469 A
7,611,926 A	701,260 A	2,262,429 A	2,603,295 A	1,245,402 A	799,540 A
U	U	U	U	U	U
7,611,926 A	701,260 A	2,262,429 A	2,603,295 A	1,245,402 A	799,540 A
2,668,554 A	163,837 A	591,094 A	854,828 A	522,890 A	535,905 A
884,632 A	35,245 M	130,721 M	419,631 A	134,471 A	164,564 A
U	U	U	U	U	U
6,452,608 A	390,576 A	1,527,871 A	2,394,414 A	1,139,211 A	1,000,536 A
4,711,331 A	509,766 A	1,456,373 A	1,485,316 A	763,552 A	496,324 A
U	U	U	U	U	U
4,711,331 A	509,766 A	1,456,373 A	1,485,316 A	763,552 A	496,324 A
5,042,996 A	333,738 A	1,272,615 A	1,849,321 A	811,908 A	775,414 A
1,409,611 A	56,837 A	255,256 A	545,093 A	327,303 A	225,122 A
U	U	U	U	U	U

7.2 Outdoor motion detectors

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households with outside lights with motion detectors								
Yes	3,096,372	A	489,110	A	131,006	M	37,270	M
No	4,091,143	A	1,228,806	A	1,917,354	A	157,906	A
Don't know		U		U		U		U
Number of outside lights with motion detectors								
0	4,091,143	A	1,228,806	A	1,917,354	A	157,906	A
1	1,657,623	A	314,497	A	77,550	M		U
2 or more	1,438,748	A	174,613	A		U		U
Don't know		U		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 7.2

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
3,753,757	A	294,591	A	617,955	A	1,491,732	A	661,772	A	687,707	A
7,395,209	A	604,342	A	2,363,233	A	2,381,796	A	1,237,491	A	808,347	A
	U		U		U		U		U		U
7,395,209	A	604,342	A	2,363,233	A	2,381,796	A	1,237,491	A	808,347	A
2,073,963	A	183,130	A	366,465	A	852,041	A	378,955	A	293,371	A
1,679,795	A	111,461	A	251,490	A	639,691	A	282,816	A	394,336	A
	U		U		U		U		U		U

7.3 Light bulb usage levels and wattage

BY TYPE OF DWELLING

	Single detached		Double/row house		Apartment		Mobile home	
Households that use ordinary light bulbs for more than three hours								
Yes	4,385,465	A	1,079,866	A	1,351,388	A	121,637	A
No	2,804,993	A	639,108	A	709,869	A	73,539	A
Don't know		U		U		U		U
Households with ordinary light bulbs used more than three hours a day in standard socket								
Yes	3,819,864	A	971,496	A	1,198,396	A	116,566	A
No	558,054	A	108,370	M	152,992	A		U
Don't know		U		U		U		U
Number of ordinary light bulbs used more than three hours a day in standard sockets								
1 to 5 bulbs	2,826,961	A	785,109	A	1,108,121	A	96,668	A
6 to 10 bulbs	828,946	A	163,994	A	81,578	M		U
11 bulbs or more	160,128	A		U		U		U
Don't know		U		U		U		U
Wattage of main ordinary light bulb used more than three hours a day in standard socket								
25 to 75 watts	3,009,895	A	784,372	A	965,852	A	88,569	A
76 to 120 watts	717,633	A	174,623	A	191,426	A		U
121 watts or more		U		U		U		U
Don't know		U		U		U		U
Use of main ordinary light bulb used more than three hours a day in standard socket								
3 to 5 hours	2,308,429	A	532,605	A	698,572	A	53,035	M
6 to 10 hours	1,207,971	A	374,161	A	397,923	A	45,206	M
11 to 24 hours	251,720	A		U	92,328	M		U
Don't know		U		U		U		U
Wattage of secondary ordinary light bulb used more than three hours a day in standard socket								
25 to 75 watts	2,606,125	A	562,218	A	674,224	A	81,320	A
76 to 120 watts	426,037	A	143,429	A	94,834	M		U
121 watts or more		U		U		U		U
Don't know	95,228	M		U		U		U
Use of secondary ordinary light bulb used more than three hours a day in standard socket								
3 to 5 hours	2,453,422	A	517,743	A	628,351	A	78,903	A
6 to 10 hours	517,481	A	131,438	A	122,551	M		U
11 to 24 hours	75,850	M		U		U		U
Don't know	111,258	M		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 7.3

BY REGION

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
6,938,356	A	546,241	A	2,024,698	A	2,299,080	A	1,154,075	A	914,261	A
4,227,509	A	354,101	A	957,103	A	1,582,951	A	748,688	A	584,666	A
	U		U		U		U		U		U
6,106,321	A	502,285	A	1,699,165	A	2,002,587	A	1,075,928	A	826,356	A
824,488	A	43,956	A	322,165	A	295,006	A	78,147	A	85,214	A
	U		U		U		U		U		U
4,816,859	A	361,046	A	1,398,302	A	1,565,454	A	831,149	A	660,909	A
1,091,325	A	106,642	A	260,265	A	379,879	A	208,417	A	136,122	A
192,042	A	34,597	A		U		U		U		U
	U		U		U		U		U		U
4,848,689	A	425,167	A	1,352,528	A	1,649,555	A	833,785	A	587,653	A
1,111,677	A	71,139	A	321,055	A	300,948	A	207,709	A	210,826	A
110,424	M		U		U		U		U		U
	U		U		U		U		U		U
3,592,641	A	246,842	A	969,902	A	1,186,744	A	695,408	A	493,745	A
2,025,261	A	201,415	A	571,197	A	675,738	A	302,174	A	274,737	A
425,318	A	53,175	A	143,263	M	123,896	M	51,206	M	53,777	M
	U		U		U		U		U		U
3,923,887	A	342,343	A	1,142,062	A	1,337,582	A	606,191	A	495,709	A
682,811	A	56,050	A	140,582	M	186,682	A	194,578	A	104,918	A
	U		U		U		U		U		U
119,485	M		U		U		U		U		U
3,678,419	A	314,990	A	965,408	A	1,223,109	A	682,687	A	492,226	A
790,454	A	66,427	A	257,061	A	259,063	A	110,580	A	97,324	A
142,701	M		U		U		U		U		U
157,397	M		U		U		U		U		U

SECTION 8

Energy Consumption and Energy Intensity

8.1 Total energy consumption (GJ) and total energy intensity (GJ/m²) by region

TOTAL ENERGY CONSUMPTION (GJ)[a]

	Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
Total	1,381,387,172	A	110,021,696	A	295,614,183	A	536,659,798	A	279,288,330	A	159,803,165	A
Type of dwelling												
Single detached	989,469,153	A	78,325,438	A	171,198,397	A	407,482,770	A	217,326,951	A	115,135,597	A
Double/row house	193,354,228	A	8,827,313	M	46,329,903	A	85,936,516	A	33,898,503	M	18,361,993	M
Apartment	180,670,210	A		U	75,815,548	A		U		U	23,333,710	M
Mobile home	17,893,581	A		U		U		U		U		U
Construction period												
Before 1946	209,309,834	A	26,956,645	M	48,865,719	M	83,310,666	M	36,586,958	A		U
1946–1969	397,759,871	A	20,406,707	A	92,162,307	A	168,333,275	A	82,159,406	A	34,698,175	A
1970–1979	278,932,719	A	24,354,897	A	67,240,037	A	94,546,262	M	61,946,201	A	30,845,321	A
1980–1989	234,334,071	A	16,264,593	A	44,488,147	A	92,414,195	A	47,403,268	M	33,763,868	A
1990–2003	261,050,677	A	22,038,854	M	42,857,972	A	98,055,401	A	51,192,496	A	46,905,954	A
Type of population centre												
Urban	1,164,348,155	A	77,376,185	A	252,944,631	A	466,959,075	A	226,207,642	A	140,860,623	A
Rural	217,039,016	A	32,645,512	A	42,669,552	A	69,700,723	A	53,080,688	A	18,942,541	M
Household income												
Less than $20,000	103,180,773	A	17,397,138	M	25,421,041	M		U	18,234,857	M	12,416,479	M
$20,000 to $39,999	210,707,665	A	19,755,618	A	55,001,597	A	70,917,742	A	43,904,017	A	21,128,691	M
$40,000 to $59,999	217,397,392	A	19,248,707	A	45,061,492	A	78,683,247	M	53,399,512	A	21,004,435	A
$60,000 to $79,999	183,207,924	A	12,265,045	A	33,816,219	A	73,062,739	A	38,228,316	A	25,835,605	M
$80,000 or more	587,391,835	A	38,064,590	A	123,683,411	A	250,195,525	A	104,674,843	A	70,773,465	A
Not stated	79,501,583	A		U		U	34,089,288	M		U		U
Occupation mode												
Owner	1,111,289,174	A	81,551,916	A	208,793,178	A	456,096,867	A	233,940,893	A	130,906,319	A
Renter	270,070,393	A	28,469,781	M	86,821,005	A	80,562,931	M	45,347,436	M	28,869,240	A
Not stated		U		U		U		U		U		U
Household size												
1 member	237,166,578	A	27,470,196	A	53,117,994	A	74,213,811	A	52,741,584	A	29,622,992	A
2 members	493,627,047	A	40,211,575	A	120,508,314	A	177,959,916	A	96,542,820	A	58,404,422	A
3 members	216,426,974	A	16,569,873	A	40,304,497	A	86,067,527	A	49,882,479	A	23,602,597	A
4 members or more	434,166,573	A	25,770,052	A	81,683,378	A	198,418,543	A	80,121,447	A	48,173,153	A

[a] Includes the categories of electricity, natural gas, heating oil, propane.
The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 8.1

TOTAL ENERGY INTENSITY (GJ/M²)

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
1.01 A	1.06 A	0.94 A	0.99 A	1.31 A	0.80 A
1.00 A	0.95 A	0.96 A	0.98 A	1.32 A	0.80 A
0.95 A	0.92 M	0.91 A	0.96 A	1.24 M	0.74 M
1.10 A	U	0.95 A	U	U	0.86 M
1.01 A	U	U	U	U	U
1.09 A	1.16 M	0.98 M	1.15 M	1.21 A	U
1.15 A	1.10 A	1.10 A	1.12 A	1.54 A	0.87 A
1.05 A	1.10 A	1.01 A	1.04 M	1.32 A	0.79 A
0.87 A	0.82 A	0.76 A	0.87 A	1.29 M	0.74 A
0.87 A	1.09 M	0.80 A	0.82 A	1.12 A	0.79 A
1.03 A	1.23 A	0.98 A	1.01 A	1.33 A	0.82 A
0.89 A	0.80 A	0.77 A	0.90 A	1.23 A	0.68 M
1.06 A	1.38 M	0.89 M	U	1.39 M	0.73 M
1.07 A	1.04 A	0.94 A	1.13 A	1.41 A	0.83 M
1.06 A	0.97 A	0.96 A	1.08 M	1.42 A	0.73 A
0.97 A	1.27 A	0.84 A	0.95 A	1.19 A	0.89 M
0.97 A	0.99 A	0.95 A	0.94 A	1.23 A	0.79 A
1.05 A	U	U	0.92 M	U	U
1.00 A	0.95 A	0.96 A	0.97 A	1.28 A	0.82 A
1.06 A	1.56 M	0.91 A	1.17 M	1.45 M	0.71 A
U	U	U	U	U	U
1.04 A	1.32 A	0.95 A	0.97 A	1.45 A	0.78 A
1.02 A	0.99 A	0.97 A	1.03 A	1.32 A	0.81 A
0.97 A	0.95 A	0.83 A	0.99 A	1.31 A	0.76 A
0.99 A	1.01 A	0.97 A	0.98 A	1.22 A	0.81 A

8.1 Total energy consumption (GJ) and total energy intensity (GJ/m²) by region

TOTAL ENERGY CONSUMPTION (GJ)[a]

	Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
Heated area of dwelling						
56 square metres or less						
(600 square feet or less)	69,693,996 A	U	24,872,013 A	U	U	U
56 to 93 square metres						
(601 to 1,000 square feet)	318,032,635 A	30,565,101 A	95,302,297 A	81,009,920 A	80,958,192 A	30,197,125 A
93 to 139 square metres						
(1,001 to 1,500 square feet)	488,740,666 A	35,516,093 A	96,397,907 A	188,227,839 A	114,341,033 A	54,257,795 A
139 to 186 square metres						
(1,501 to 2,000 square feet)	261,433,002 A	18,434,456 A	44,695,086 M	118,336,415 A	50,413,465 A	29,553,580 A
186 to 232 square metres						
(2,001 to 2,500 square feet)	93,385,017 A	U	U	46,935,601 M	U	15,220,696 M
232 or more square metres						
(2,501 or more square feet)	150,101,857 A	U	U	81,064,321 M	U	25,915,535 M

[a] Includes the categories of electricity, natural gas, heating oil, propane.
The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 8.1 (cont. 2/2)

TOTAL ENERGY INTENSITY (GJ/M^2)

Canada		Atlantic		Quebec		Ontario		Prairies		British Columbia	
1.63	A		U	1.40	A		U		U		U
1.25	A	1.23	A	1.09	A	1.41	A	1.60	A	0.88	A
1.05	A	0.96	A	0.92	A	1.05	A	1.34	A	0.92	A
0.89	A	0.90	A	0.81	M	0.91	A	1.05	A	0.77	A
0.78	A		U		U	0.76	M		U	0.71	M
0.77	A		U		U	0.81	M		U	0.61	M

8.2 Total energy consumption (GJ) and total energy intensity (GJ/m^2) by type of dwelling

TOTAL ENERGY CONSUMPTION (GJ)[a]

	Single detached		Double/row house		Apartment		Mobile home	
Region								
Atlantic	78,325,438	A	8,827,313	M		U		U
Quebec	171,198,397	A	46,329,903	A	75,815,548	A		U
Ontario	407,482,770	A	85,936,516	A		U		U
Prairies	217,326,951	A	33,898,503	M		U		U
British Columbia	115,135,597	A	18,361,993	M	23,333,710	M		U
Construction period								
Before 1946	148,245,492	A	28,788,835	M		U		U
1946–1969	291,738,746	A	44,878,574	M	59,138,419	M		U
1970–1979	187,451,766	A	45,524,652	M		U	9,888,478	M
1980–1989	165,623,267	A	38,227,989	M	27,634,967	M		U
1990–2003	196,409,882	A	35,934,178	M	23,466,868	M		U
Type of population centre								
Urban	791,810,916	A	185,480,871	A	175,650,334	A	9,319,409	M
Rural	197,658,237	A		U		U	8,574,173	M
Household income								
Less than $20,000	47,942,642	A	35,875,636	M	15,950,347	M		U
$20,000 to $39,999	118,244,422	A	54,254,368	M	33,345,843	A		U
$40,000 to $59,999	144,075,678	A		U	40,465,837	M		U
$60,000 to $79,999	135,500,138	A		U	32,155,501	A		U
$80,000 or more	478,911,827	A	38,471,090	M	64,245,415	A		U
Not stated	64,794,445	A		U		U		U
Occupation mode								
Owner	943,572,705	A	120,788,461	A	30,533,774	M	16,394,234	A
Renter	45,896,448	A	72,538,161	M	148,049,809	A		U
Not stated		U		U		U		U
Household size								
1 member	114,452,108	A	33,984,454	M	84,314,441	M		U
2 members	358,830,365	A	62,344,240	A	62,948,487	M	7,417,330	M
3 members	164,782,645	A	33,711,868	A	15,645,467	M		U
4 members or more	351,404,034	A	63,313,667	M	15,675,189	M		U
Heated area of dwelling								
56 square metres or less (600 square feet or less)	19,183,833	M		U	43,290,068	M		U
56 to 93 square metres (601 to 1,000 square feet)	181,100,288	A	46,684,921	A	81,981,718	M	8,265,708	A
93 to 139 square metres (1,001 to 1,500 square feet)	364,212,741	A	83,438,176	A	33,682,293	M	7,407,456	M
139 to 186 square metres (1,501 to 2,000 square feet)	217,701,975	A	31,462,157	M		U		U
186 to 232 square metres (2,001 to 2,500 square feet)	85,460,479	A		U		U		U
232 or more square metres (2,501 or more square feet)	121,809,837	A		U		U		U

[a] Includes the categories of electricity, natural gas, heating oil, propane.
The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 8.2

TOTAL ENERGY INTENSITY (GJ/M²)

	Single detached	Double/row house	Apartment	Mobile home
	0.95 A	0.92 M	U	U
	0.96 A	0.91 A	0.95 A	U
	0.98 A	0.96 A	U	U
	1.32 A	1.24 M	U	U
	0.80 A	0.74 M	0.86 M	U
	1.07 A	0.96 M	U	U
	1.16 A	1.01 M	1.25 M	U
	1.09 A	0.98 M	U	1.09 M
	0.85 A	1.03 M	0.86 M	U
	0.87 A	0.81 M	1.02 M	U
	1.04 A	0.95 A	1.10 A	1.02 M
	0.88 A	U	U	0.99 M
	0.98 A	1.06 M	1.21 M	U
	1.05 A	0.92 A	1.27 M	U
	1.05 A	0.99 M	U	U
	0.99 A	0.95 A	U	U
	0.98 A	0.91 A	0.87 M	U
	1.03 A	U	U	U
	1.01 A	0.94 A	0.88 M	0.99 A
	0.96 A	0.98 M	1.15 A	U
	U	U	U	U
	1.01 A	1.00 M	1.12 M	U
	1.02 A	0.94 A	1.18 M	0.94 M
	1.01 A	0.88 A	0.80 M	U
	0.99 A	0.99 M	1.07 M	U
	1.83 M	U	1.63 M	U
	1.36 A	1.14 A	1.12 M	1.02 A
	1.11 A	0.90 A	0.92 M	0.98 M
	0.90 A	0.81 M	U	U
	0.81 A	U	U	U
	0.74 A	U	U	U

8.3 Total electricity consumption (GJ) and total electricity intensity (GJ/m²) by region

TOTAL ELECTRICITY CONSUMPTION (GJ)

	Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
Total	534,044,816 A	49,243,814 A	202,723,538 A	158,465,528 A	63,484,823 A	60,127,113 A
Type of dwelling						
Single detached	372,425,854 A	36,560,902 A	123,710,747 A	119,562,740 A	49,791,387 A	42,800,078 A
Double/row house	75,364,807 A	4,683,035 A	32,372,134 A	24,356,630 A	6,466,971 A	7,486,036 A
Apartment	76,911,109 A	6,334,008 M	44,387,394 A	13,873,710 M	4,252,102 M	8,063,894 A
Mobile home	9,343,046 A	1,665,868 M	U	U	2,974,363 M	U
Construction period						
Before 1946	69,042,664 A	7,387,757 A	26,700,408 A	20,784,040 A	9,110,830 A	5,059,628 M
1946–1969	135,810,403 A	7,933,404 A	52,879,049 A	45,090,406 A	17,249,549 A	12,657,995 A
1970–1979	113,780,986 A	11,773,575 A	45,460,569 A	31,115,908 A	13,591,991 A	11,838,942 A
1980–1989	109,030,901 A	10,297,043 A	41,487,341 A	31,274,872 A	12,245,632 A	13,726,013 A
1990–2003	106,379,862 A	11,852,034 A	36,196,171 A	30,200,301 A	11,286,821 A	16,844,535 A
Type of population centre						
Urban	426,645,442 A	33,101,166 A	168,967,865 A	128,723,913 A	45,794,653 A	50,057,844 A
Rural	107,399,373 A	16,142,648 A	33,755,673 A	29,741,614 A	17,690,170 A	10,069,269 M
Household income						
Less than $20,000	44,810,838 A	8,408,373 A	16,935,520 A	10,857,868 M	4,280,417 M	4,328,660 A
$20,000 to $39,999	80,207,549 A	7,900,688 A	34,530,142 A	19,197,570 A	11,257,987 A	7,321,162 A
$40,000 to $59,999	78,716,459 A	9,353,256 A	28,816,854 A	21,082,693 A	10,551,094 A	8,912,562 M
$60,000 to $79,999	70,249,788 A	4,896,976 A	26,426,975 A	21,463,552 A	8,296,213 A	9,166,072 M
$80,000 or more	235,833,150 A	17,104,534 A	89,129,715 A	76,307,079 A	25,203,806 A	28,088,017 A
Not stated	24,227,032 A	U	U	9,556,766 M	3,895,305 M	U
Occupation mode						
Owner	422,137,091 A	38,180,909 A	151,176,222 A	131,617,719 A	54,149,052 A	47,013,188 A
Renter	111,880,119 A	11,062,905 A	51,547,316 A	26,847,808 A	9,335,771 A	13,086,320 A
Not stated	U	U	U	U	U	U
Household size						
1 member	89,197,403 A	12,042,962 A	33,647,413 A	22,168,185 A	10,550,736 A	10,788,106 A
2 members	187,903,966 A	16,517,323 A	77,167,159 A	50,471,385 A	22,638,884 A	21,109,214 A
3 members	91,470,598 A	9,260,745 A	31,094,674 A	29,773,401 A	11,505,247 A	9,836,530 A
4 members or more	165,472,849 A	11,422,783 A	60,814,291 A	56,052,556 A	18,789,956 A	18,393,263 A

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 8.3

TOTAL ELECTRICITY INTENSITY (GJ/M²)

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
0.39 A	0.47 A	0.65 A	0.29 A	0.30 A	0.30 A
0.38 A	0.45 A	0.69 A	0.29 A	0.30 A	0.30 A
0.37 A	0.49 A	0.63 A	0.27 A	0.24 A	0.30 A
0.47 A	0.65 M	0.55 A	0.43 M	0.28 M	0.30 A
0.53 A	0.61 M	U	U	0.53 M	U
0.36 A	0.32 A	0.53 A	0.29 A	0.30 A	0.33 M
0.39 A	0.43 A	0.63 A	0.30 A	0.32 A	0.32 A
0.43 A	0.53 A	0.68 A	0.34 A	0.29 A	0.30 A
0.41 A	0.52 A	0.71 A	0.29 A	0.34 A	0.30 A
0.35 A	0.58 A	0.67 A	0.25 A	0.25 A	0.28 A
0.38 A	0.52 A	0.66 A	0.28 A	0.27 A	0.29 A
0.44 A	0.39 A	0.61 A	0.38 A	0.41 A	0.36 M
0.46 A	0.67 A	0.60 A	0.42 M	0.33 M	0.25 A
0.41 A	0.41 A	0.59 A	0.31 A	0.36 A	0.29 A
0.38 A	0.47 A	0.61 A	0.29 A	0.28 A	0.31 M
0.37 A	0.51 A	0.65 A	0.28 A	0.26 A	0.32 M
0.39 A	0.44 A	0.69 A	0.29 A	0.30 A	0.31 A
0.32 A	U	U	0.26 M	0.28 M	U
0.38 A	0.44 A	0.69 A	0.28 A	0.30 A	0.30 A
0.44 A	0.61 A	0.54 A	0.39 A	0.30 A	0.32 A
U	U	U	U	U	U
0.39 A	0.58 A	0.60 A	0.29 A	0.29 A	0.29 A
0.39 A	0.41 A	0.62 A	0.29 A	0.31 A	0.29 A
0.41 A	0.53 A	0.64 A	0.34 A	0.30 A	0.32 A
0.38 A	0.45 A	0.72 A	0.28 A	0.29 A	0.31 A

8.3 Total electricity consumption (GJ) and total electricity intensity (GJ/m²) by region

TOTAL ELECTRICITY CONSUMPTION (GJ)	Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
Heated area of dwelling						
56 square metres or less (600 square feet or less)	29,411,810 A	2,609,860 M	16,195,098 A	U	2,642,894 M	U
56 to 93 square metres (601 to 1,000 square feet)	137,711,704 A	15,906,069 A	69,384,837 A	21,580,207 A	18,751,899 A	12,088,692 A
93 to 139 square metres (1,001 to 1,500 square feet)	192,707,113 A	17,782,559 A	68,065,603 A	59,742,436 A	26,332,774 A	20,783,740 A
139 to 186 square metres (1,501 to 2,000 square feet)	92,268,363 A	7,057,356 A	28,925,419 A	34,245,741 A	10,495,932 A	11,543,915 A
186 to 232 square metres (2,001 to 2,500 square feet)	33,550,728 A	U	U	14,244,056 M	U	4,325,720 M
232 or more square metres (2,501 or more square feet)	48,395,098 A	U	U	22,370,322 M	U	9,703,854 M

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use.*

Table 8.3 (cont. 2/2)

TOTAL ELECTRICITY INTENSITY (GJ/M²)

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
0.69 A	0.79 M	0.91 A	U	0.43 M	U
0.54 A	0.64 A	0.79 A	0.38 A	0.37 A	0.35 A
0.41 A	0.48 A	0.65 A	0.33 A	0.31 A	0.35 A
0.32 A	0.34 A	0.52 A	0.26 A	0.22 A	0.30 A
0.28 A	U	U	0.23 M	U	0.20 M
0.25 A	U	U	0.22 M	U	0.23 M

8.4 Total electricity consumption (GJ) and total electricity intensity (GJ/m²) by type of dwelling

TOTAL ELECTRICITY CONSUMPTION (GJ)

	Single detached		Double/row house		Apartment		Mobile home	
Region								
Atlantic	36,560,902	A	4,683,035	A	6,334,008	M	1,665,868	M
Quebec	123,710,747	A	32,372,134	A	44,387,394	A		U
Ontario	119,562,740	A	24,356,630	A	13,873,710	M		U
Prairies	49,791,387	A	6,466,971	A	4,252,102	M	2,974,363	M
British Columbia	42,800,078	A	7,486,036	A	8,063,894	A		U
Construction period								
Before 1946	46,440,500	A	12,244,858	M	10,357,306	M		U
1946–1969	99,080,907	A	16,999,601	M	19,018,705	M		U
1970–1979	74,184,654	A	17,704,930	A		U	4,637,812	M
1980–1989	74,580,176	A	15,316,568	A	17,093,982	M		U
1990–2003	78,139,617	A	13,098,850	A	13,187,526	A		U
Type of population centre								
Urban	275,641,043	A	71,119,566	A	75,188,134	A	4,696,700	M
Rural	96,784,811	A		U		U	4,646,346	A
Household income								
Less than $20,000	20,579,518	A	6,510,315	M	16,888,922	A		U
$20,000 to $39,999	44,000,039	A	14,425,775	A	19,210,111	A	2,571,623	M
$40,000 to $59,999	51,096,701	A	15,760,406	M	9,788,420	A		U
$60,000 to $79,999	52,027,646	A	11,213,239	M	6,625,905	M		U
$80,000 or more	184,622,484	A	25,555,533	A	22,335,357	M	3,319,776	M
Not stated	20,099,465	A		U		U		U
Occupation mode								
Owner	353,754,016	A	43,424,951	A	16,329,012	A	8,629,113	A
Renter	18,671,838	A	31,912,251	A	60,582,096	A		U
Not stated		U		U		U		U
Household size								
1 member	40,990,282	A	12,125,352	A	33,798,098	A		U
2 members	132,939,755	A	25,070,744	A	26,081,471	A	3,811,996	M
3 members	64,050,925	A	16,263,430	A	9,832,386	M		U
4 members or more	134,444,892	A	21,905,281	A	7,199,154	M		U
Heated area of dwelling								
56 square metres or less (600 square feet or less)	8,693,533	A	4,121,148	M	16,237,717	A		U
56 to 93 square metres (601 to 1,000 square feet)	76,302,901	A	20,893,746	A	36,055,630	A	4,459,427	M
93 to 139 square metres (1,001 to 1,500 square feet)	141,662,344	A	32,968,721	A	13,906,902	A	4,169,145	M
139 to 186 square metres (1,501 to 2,000 square feet)	77,887,033	A	10,381,829	M		U		U
186 to 232 square metres (2,001 to 2,500 square feet)	28,521,822	A		U		U		U
232 or more square metres (2,501 or more square feet)	39,358,220	A		U		U		U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 8.4

TOTAL ELECTRICITY INTENSITY (GJ/M²)

	Single detached	Double/row house	Apartment	Mobile home
	0.45 A	0.49 A	0.65 M	0.61 M
	0.69 A	0.63 A	0.55 A	U
	0.29 A	0.27 A	0.43 M	U
	0.30 A	0.24 A	0.28 M	0.53 M
	0.30 A	0.30 A	0.30 A	U
	0.33 A	0.41 M	0.46 M	U
	0.39 A	0.38 M	0.40 M	U
	0.43 A	0.38 A	U	0.51 M
	0.38 A	0.42 A	0.53 M	U
	0.34 A	0.30 A	0.53 A	U
	0.36 A	0.37 A	0.47 A	0.52 M
	0.43 A	U	U	0.54 A
	0.42 A	0.43 M	0.54 A	U
	0.39 A	0.40 A	0.45 A	0.56 M
	0.37 A	0.39 M	0.41 A	U
	0.38 A	0.33 M	0.38 M	U
	0.38 A	0.36 A	0.51 M	0.53 M
	0.32 A	U	U	U
	0.38 A	0.34 A	0.47 A	0.52 A
	0.39 A	0.43 A	0.46 A	U
	U	U	U	U
	0.36 A	0.36 A	0.45 A	U
	0.38 A	0.38 A	0.47 A	0.48 M
	0.39 A	0.43 A	0.50 M	U
	0.38 A	0.35 A	0.49 M	U
	0.83 A	0.81 M	0.61 A	U
	0.57 A	0.51 A	0.49 A	0.55 M
	0.43 A	0.36 A	0.38 A	0.55 M
	0.32 A	0.27 M	U	U
	0.27 A	U	U	U
	0.24 A	U	U	U

8.5 Total natural gas consumption (GJ) and total natural gas intensity (GJ/m²) by region

TOTAL NATURAL GAS CONSUMPTION (GJ)

	Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
Total	672,548,837 A	U	34,124,861 M	333,021,203 A	212,294,744 A	92,820,325 A
Type of dwelling						
Single detached	494,561,624 A	U	U	250,298,904 A	165,351,945 A	65,734,279 A
Double/row house	105,384,128 A	U	U	60,771,162 A	27,431,533 M	10,751,336 M
Apartment	65,966,137 A	U	U	U	U	U
Mobile home	6,636,947 M	U	U	U	U	U
Construction period						
Before 1946	81,703,031 A	U	U	42,046,800 A	26,907,808 A	U
1946–1969	208,652,830 A	U	U	111,800,797 A	63,937,568 A	19,096,270 A
1970–1979	133,682,650 A	U	U	58,659,909 A	46,920,327 A	16,881,402 A
1980–1989	112,068,674 A	U	U	56,147,624 A	34,952,184 M	19,735,770 A
1990–2003	136,441,652 A	U	U	64,366,073 A	39,576,857 A	29,605,272 M
Type of population centre						
Urban	616,326,478 A	U	U	315,474,801 A	179,967,057 A	86,706,588 A
Rural	56,222,359 A	U	U	17,546,403 M	32,327,688 A	U
Household income						
Less than $20,000	40,928,903 A	U	U	U	13,713,833 M	U
$20,000 to $39,999	96,148,094 A	U	U	45,214,350 A	31,442,451 A	13,470,793 M
$40,000 to $59,999	110,440,134 A	U	U	46,836,109 M	42,326,790 M	10,794,899 A
$60,000 to $79,999	92,369,384 A	U	U	47,071,952 A	29,435,896 A	15,570,839 M
$80,000 or more	287,236,623 A	U	U	155,745,141 A	78,522,670 A	39,828,975 A
Not stated	45,425,700 A	U	U	21,978,502 M	U	U
Occupation mode						
Owner	558,714,120 A	U	U	287,144,005 A	177,297,236 A	78,369,604 A
Renter	113,834,716 A	U	U	45,877,199 M	34,997,508 M	14,450,721 M
Not stated	U	U	U	U	U	U
Household size						
1 member	103,773,365 A	U	U	39,761,397 A	41,413,862 M	16,777,726 M
2 members	236,424,922 A	U	U	107,793,726 A	72,848,535 A	35,011,613 A
3 members	103,156,832 A	U	U	51,360,644 A	36,848,299 A	12,814,839 M
4 members or more	229,193,718 A	U	U	134,105,436 A	61,184,048 A	28,216,146 A

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 8.5

TOTAL NATURAL GAS INTENSITY (GJ/M²)

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
0.85 A	U	1.28 M	0.77 A	1.09 A	0.65 A
0.84 A	U	U	0.76 A	1.10 A	0.64 A
0.81 A	U	U	0.75 A	1.02 M	0.64 M
1.03 A	U	U	U	U	U
0.87 M	U	U	U	U	U
0.88 A	U	U	0.84 A	1.00 A	U
0.98 A	U	U	0.90 A	1.28 A	0.72 A
0.92 A	U	U	0.83 A	1.10 A	0.62 A
0.77 A	U	U	0.70 A	1.12 M	0.61 A
0.69 A	U	U	0.62 A	0.91 A	0.65 M
0.85 A	U	U	0.79 A	1.09 A	0.65 A
0.82 A	U	U	0.62 M	1.08 A	U
1.02 A	U	U	U	1.19 M	U
0.99 A	U	U	0.92 A	1.17 A	0.78 M
0.94 A	U	U	0.82 M	1.21 M	0.59 A
0.80 A	U	U	0.73 A	1.02 A	0.71 M
0.78 A	U	U	0.74 A	1.00 A	0.60 A
0.82 A	U	U	0.69 M	U	U
0.82 A	U	U	0.75 A	1.07 A	0.67 A
1.01 A	U	U	1.01 M	1.23 M	0.58 M
U	U	U	U	U	U
0.91 A	U	U	0.76 A	1.29 M	0.69 M
0.91 A	U	U	0.83 A	1.09 A	0.70 A
0.80 A	U	U	0.73 A	1.08 A	0.58 M
0.79 A	U	U	0.75 A	1.00 A	0.61 A

8.5 Total natural gas consumption (GJ) and total natural gas intensity (GJ/m²) by region

TOTAL NATURAL GAS CONSUMPTION (GJ)

	Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
Heated area of dwelling						
56 square metres or less (600 square feet or less)	28,631,776 A	U	U	U	U	U
56 to 93 square metres (601 to 1,000 square feet)	141,177,415 A	U	U	49,248,876 A	60,415,608 A	16,663,259 M
93 to 139 square metres (1,001 to 1,500 square feet)	232,505,587 A	U	U	109,169,267 A	86,966,207 A	29,450,666 A
139 to 186 square metres (1,501 to 2,000 square feet)	134,913,184 A	U	U	76,347,047 A	39,703,451 A	17,783,123 M
186 to 232 square metres (2,001 to 2,500 square feet)	49,838,306 A	U	U	31,088,040 M	U	10,315,381 M
232 or more square metres (2,501 or more square feet)	85,482,569 A	U	U	53,594,042 M	U	15,630,653 M

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 8.5 (cont. 2/2)

TOTAL NATURAL GAS INTENSITY (GJ/M²)

Canada	Atlantic	Quebec	Ontario	Prairies	British Columbia
1.42 A	U	U	U	U	U
1.18 A	U	U	1.11 A	1.35 A	0.71 M
0.90 A	U	U	0.80 A	1.12 A	0.79 A
0.74 A	U	U	0.73 A	0.88 A	0.60 M
0.62 A	U	U	0.60 M	U	0.56 M
0.64 A	U	U	0.62 M	U	0.52 M

8.6 Total natural gas consumption (GJ) and total natural gas intensity (GJ/m²) by type of dwelling

TOTAL NATURAL GAS CONSUMPTION (GJ)

	Single detached	Double/row house	Apartment	Mobile home
Region				
Atlantic	U	U	U	U
Quebec	U	U	U	U
Ontario	250,298,904 A	60,771,162 A	U	U
Prairies	165,351,945 A	27,431,533 M	U	U
British Columbia	65,734,279 A	10,751,336 M	U	U
Construction period				
Before 1946	63,678,950 A	U	U	U
1946–1969	155,104,617 A	22,880,860 M	U	U
1970–1979	90,493,457 A	26,519,923 M	U	U
1980–1989	80,584,775 A	21,777,023 M	U	U
1990–2003	104,699,826 A	22,401,325 M	U	U
Type of population centre				
Urban	442,722,617 A	103,640,183 A	65,864,925 M	U
Rural	51,839,007 A	U	U	U
Household income				
Less than $20,000	18,546,128 M	U	U	U
$20,000 to $39,999	57,105,006 A	13,908,121 M	U	U
$40,000 to $59,999	75,480,138 A	U	U	U
$60,000 to $79,999	65,665,825 A	20,129,328 M	U	U
$80,000 or more	239,514,810 A	35,189,929 M	U	U
Not stated	38,249,717 A	U	U	U
Occupation mode				
Owner	471,342,307 A	69,745,898 A	U	6,062,353 M
Renter	23,219,317 A	U	U	U
Not stated	U	U	U	U
Household size				
1 member	54,753,996 A	U	U	U
2 members	171,805,265 A	33,862,881 M	U	U
3 members	82,917,339 A	15,800,048 M	U	U
4 members or more	185,085,024 A	38,340,027 M	U	U
Heated area of dwelling				
56 square metres or less (600 square feet or less)	U	U	U	U
56 to 93 square metres (601 to 1,000 square feet)	87,160,997 A	20,352,948 M	U	U
93 to 139 square metres (1,001 to 1,500 square feet)	170,909,419 A	46,478,032 A	U	U
139 to 186 square metres (1,501 to 2,000 square feet)	113,596,603 A	19,688,566 M	U	U
186 to 232 square metres (2,001 to 2,500 square feet)	47,182,244 A	U	U	U
232 or more square metres (2,501 or more square feet)	69,246,773 A	U	U	U

The letter beside each estimate classifies its quality as follows: A – Acceptable, M – Use with caution, U – Too unreliable to be published.
Due to rounding the numbers may not add up and may differ slightly among tables. Source: *2003 Survey of Household Energy Use*.

Table 8.6

TOTAL NATURAL GAS INTENSITY (GJ/M^2)

	Single detached	Double/row house	Apartment	Mobile home
	U	U	U	U
	U	U	U	U
	0.76 A	0.75 A	U	U
	1.10 A	1.02 M	U	U
	0.64 A	0.64 M	U	U
	0.87 A	U	U	U
	0.94 A	0.92 M	U	U
	0.96 A	0.89 M	U	U
	0.73 A	0.85 M	U	U
	0.70 A	0.63 M	U	U
	0.84 A	0.81 A	1.04 M	U
	0.83 A	U	U	U
	1.01 M	U	U	U
	0.96 A	0.79 M	U	U
	0.97 A	U	U	U
	0.80 A	0.72 M	U	U
	0.78 A	0.77 M	U	U
	0.80 A	U	U	U
	0.83 A	0.74 A	U	0.87 M
	0.88 A	U	U	U
	U	U	U	U
	0.92 A	U	U	U
	0.88 A	0.83 M	U	U
	0.81 A	0.73 M	U	U
	0.79 A	0.80 M	U	U
	U	U	U	U
	1.29 A	1.05 M	U	U
	0.96 A	0.74 A	U	U
	0.75 A	0.68 M	U	U
	0.63 A	U	U	U
	0.60 A	U	U	U

APPENDIX A

Methodology

Methodology

1. Introduction

In this appendix, we outline the survey methodology used for the *2004 Survey of Household Energy Use* (SHEU), in particular the activities undertaken and the issues addressed by the methodologists of the Social Survey Methods Division (SSMD) and the Business Survey Methods Division (BSMD) of Statistics Canada.

This survey was conducted in 2004 by Statistics Canada and is therefore referred to in this methodology section as the *2004 Survey of Household Energy Use (SHEU–2004)*. However, the reference period for this survey is the calendar year 2003 (that is, all data presented are for the 2003 calendar year). Therefore, all other sections of this report and the summary report refer to the survey as the *2003 Survey of Household Energy Use (SHEU–2003)*.

This outline has been adapted from a document prepared by Statistics Canada.

To learn more about the methodological concepts or the data quality, please contact:

Special Surveys Division
Client Services
2500-R, Main Building
Tunney's Pasture
Ottawa ON K1A 0T6

Tel.: (613) 951-3321
Toll free: 1 800 461-9050
E-mail: ssd@statcan.ca

2. Pre-collection

The pre-collection period of a survey begins with the initial designing of the project and ends once data collection has started. It is a critical period, for it establishes the foundation for the entire project.

2.1 Survey objectives

The 2004 SHEU builds on the surveys of the same name that were conducted in February 1993 and February 1998. They served to gather data on the energy use characteristics of private dwellings in Canada and on household use of energy resources. The 2004 data will be used to assess the effectiveness of existing energy efficiency programs and to develop new ones.

The target population for the 2004 SHEU was composed of all dwellings that were occupied as primary residences in the 10 Canadian provinces[3] and that fit into one of the following categories: single detached, semi-detached, row, mobile, duplex or dwelling in a building with no more than four storeys (the last two categories were not covered in the 1998 edition of the SHEU). Specifically excluded from the survey's coverage were dwellings not mentioned above, dwellings located in a First Nation community or on a military base, businesses, institutions, demolished dwellings, dwellings under construction, seasonal or secondary residences, and dwellings occupied by individuals who work full-time within the Canadian Armed Forces.

As was the case in 1998, the survey sought to obtain energy consumption data directly from suppliers of electricity, natural gas, fuel oil and propane. Signed authorizations from households were required before we could contact the energy suppliers for this data. In the case of tenants, we also had to contact the non-occupant owner for certain pieces of information and to obtain authorization to contact the energy suppliers.

The sample of dwellings for the survey was designed to produce reliable estimates for each of the five large Canadian regions (Atlantic provinces, Quebec, Ontario, Prairie provinces, British Columbia) as well as national estimates for certain aggregate variables, such as groupings by type of dwelling or year built and by rural or urban location.

[3] The territories are not included in the target population.

The survey was conducted on behalf of Natural Resources Canada. Respondents, including non-occupant owners, where applicable, were informed of a data-sharing agreement under which Natural Resources Canada would have access to a complete microdata file.

2.2 Survey frame

The two main sources of data first envisaged for the SHEU survey frame were the *Labour Force Survey* (LFS) and the *Canadian Community Health Survey* (CCHS). One disadvantage of the LFS was that we had to select whole rotation groups if we wanted to avoid unduly complex variance estimation. One significant advantage of the CCHS over the LFS was that the CCHS allowed for obtaining reduced design effects, meaning that the required sample could be reduced, along with the related collection costs. The CCHS was therefore selected as the survey frame for the SHEU.

More specifically, cycle 2.1 of the CCHS was selected because its auxiliary information was current. The CCHS area frame was targeted because its coverage of the territory covered by the SHEU, i.e., the 10 Canadian provinces, was excellent. The respondents for the collection months from January to August 2003 were identified as being available for the SHEU sample.

2.3 Sample design

What follows is an overview of the sample design used for the *2004 Survey of Household Energy Use*.

The SHEU sample was composed of respondents from the area frame of the CCHS who were assigned to collection months ranging from January to August 2003. They were interviewed for the CCHS between January and October 2003 (the number of interviews done in September and October is low because only households previously flagged as unresolved were interviewed during these months). The auxiliary information available for SHEU purposes – type of dwelling, telephone number and occupant type (tenant or owner) – was therefore relatively recent when we established the sample in January 2004; the information had been gathered during the previous three to twelve months and was six months old on average. The SHEU sample design is a stratified simple random sample plan of CCHS respondents. The SHEU strata definitions are based on the provincial health regions, with some slight modifications to avoid overlap between strata of the LFS and those of the health regions (LFS strata not assigned to a single health region were assigned to one). The sample allocation to SHEU strata was proportional to population estimates. This approach to sample design, pseudo-proportional to the weight, has the advantage of reducing design effects, resulting in estimates of better quality for given sample sizes.

The sample size required to meet the analysis needs summarized in Section 2.1 – keeping in mind the use of the CCHS as survey frame, the proposed survey design and the expected response rate – was 6,433 dwellings. Tables 1 to 5 provide details on the distribution of these dwellings by regional office, province, type of dwelling, CCHS participation and type of population centre.

Table 1

Sample distribution by regional office

Regional office	Frequency	Percentage
Halifax	1,089	16.93%
Montreal	1,398	21.73%
Toronto	1,424	22.14%
Edmonton	1,358	21.11%
Vancouver	1,164	18.09%

Table 2

Sample distribution by province

Province	Frequency	Percentage
Newfoundland and Labrador	252	3.92%
Prince Edward Island	65	1.01%
Nova Scotia	429	6.67%
New Brunswick	343	5.33%
Quebec	1,398	21.73%
Ontario	1,424	22.14%
Manitoba	297	4.62%
Saskatchewan	259	4.03%
Alberta	802	12.47%
British Columbia	1,164	18.09%

Table 3

Sample distribution by type of dwelling

Type of dwelling	Frequency	Percentage
Single detached house	4,125	64.12%
Semi-detached house	317	4.93%
Double/row house	353	5.49%
Duplex	225	3.50%
Apartment in a building with fewer than five storeys	1,231	19.14%
Mobile home	182	2.83%

Table 4

Sample distribution by participation in the Canadian Community Health Survey

Participant	Frequency	Percentage
Selected	1,804	28.04%
Not selected	4,629	71.96%

Table 5

Sample distribution by type of population centre

Type of population centre	Frequency	Percentage
Rural	1,234	19.18%
Urban	5,144	79.96%
Remote	55	0.85%

2.4 Interview method

Given the nature of the survey, interviews had to be conducted in person at the respondents' dwellings, primarily to assist them in answering the questions on the characteristics of their dwelling and to obtain their authorization in writing for us to contact their energy suppliers. However, the regional offices calculated that collecting data from certain respondents would be very costly if they lived in a remote area or if there were not enough interviewers in the region. Statistics Canada's head office examined the requests from the regional offices and in most cases authorized them to conduct the interviews by telephone. The code "authorization for a telephone interview" was given to 138 households, as shown in Table 6. No information was available during or after the survey for determining the number of interviews actually conducted by telephone. In principle, telephone interviews were authorized only for these 138 dwellings, or 2.1 percent of the initial sample of 6,433. In comparison, approximately 3 percent of the 1998 SHEU interviews were done by telephone.

2.5 Questionnaire

The 2004 SHEU questionnaire had two separate parts. The first part, the more detailed of the two, was to be completed by the occupant of the dwelling selected from the sample. The shorter second part was needed for rented dwellings and condominiums. It was to be completed by the non-occupant owner in the first case and the condominium manager[4] in the second case, since tenants and condominium occupants did not know, or were unlikely to know, the information it was designed to gather.

The questionnaire was administered by the interviewer using a computer-assisted interview system that provided a set of built-in checks, such as allowable value ranges, to ensure a certain level of quality in the data.

2.6 Letter of introduction to the survey

A letter of introduction summarizing the purpose of the survey was sent out by the regional offices of Statistics Canada to the households selected from the SHEU sample shortly before the data were to be collected. This letter was designed as an incentive to participate in the survey and as an act of courtesy toward the CCHS respondents being sampled again for the SHEU. The address used came from the SHEU frame and matched the address of residence at the time of the CCHS.

Table 6

Distribution of dwellings for which a telephone interview was authorized

Province	Number of dwellings for which a telephone interview was authorized	Initial sample	Proportion of dwellings for which a telephone interview was authorized
Newfoundland and Labrador	20	252	7.9%
Prince Edward Island	0	65	–
Nova Scotia	0	429	–
New Brunswick	0	343	–
Quebec	14	1,398	1.0%
Ontario	50	1,424	3.5%
Manitoba	0	297	–
Saskatchewan	33	259	12.7%
Alberta	18	802	2.2%
British Columbia	3	1,164	0.3%
Total	**138**	**6,433**	**2.1%**

[4] For the sake of brevity, in the remainder of this report "non-occupant owner" means the non-occupant owner or the condominium manager, as the case may be.

3. Data collection

Data collection includes the work of obtaining information from individuals, households and, for the SHEU, third parties such as non-occupant owners and suppliers of energy resources. It is a costly phase, yet it is extremely important as the quality of the final product depends on it.

The first phase of data collection for the SHEU involved interviewing the occupants of the sampled dwellings and, if applicable, the non-occupant owners. Data were collected from March to June 2004 using computer-assisted personal interviews. A small proportion of interviews was done by telephone, as explained in Section 2.4.

It should be noted that the first phase of the data collection for the 1998 survey was done entirely in March, which could have influenced how the survey questions were answered. For example, the heating and the air conditioning of a dwelling probably change between March and June, and it is possible that the respondent's perception of this, despite the reference to the "heating season" and "summer season" in the survey questionnaire, was influenced by the date of the interview and its separation from the periods referred to in the questions.

The second phase of data collection was coordinated by Statistics Canada's head office. It involved gathering energy consumption data from suppliers in cases where the occupant or non-occupant owner had given his or her consent.

Respondents who took up residence in their dwelling during 2004 were not interviewed but were flagged as non-respondents when the weighting was done. The main reason for this was the fact that they would not have any energy consumption data for the 2003 reference year. Respondents who took up residence in their dwelling in 2003 were interviewed. As expected, their rates of imputation for the energy use variables are higher than the rates for the rest of the sample (except for propane).

3.1 Response rate

In order to define the response rate for the first collection phase, the SHEU sample was first divided into three mutually exclusive groups (see Table 7).

Table 7

Classification of the sample

Group	Definition	Sample
Respondent	Dwelling for which we obtained sufficient data and an authorization for data sharing.	4,551
Non-respondent	Dwelling for which we did not obtain sufficient data or an authorization for data sharing.	1,573
Unit out of scope	A dwelling whose type is incompatible with the survey: dwelling located on a military base or in a business or institution; dwelling vacant, demolished or under construction; seasonal or secondary residence; or dwelling located in a First Nation community or occupied by individuals who work full-time within the Canadian Armed Forces.	309
Total		**6,433**

We included the criteria of authorization for data sharing in the definition of "respondent" since the rate of authorization was relatively high (98 percent for occupants, 94 percent for non-occupant owners) and so we would have to produce only one file of "sharing" respondents for the survey. Table 8 shows the three types of response rates calculated.

Table 8

Definition of response rates

Rate 1	Raw response rate	= respondents/sample
Rate 2	Intermediate response rate, where out-of-scope units are omitted from the denominator	= respondents/(sample – out-of-scope units)
Rate 3	Operational response rate	= (respondents + out-of-scope units)/sample

It should be noted that these definitions do not accurately reflect the work performed in the field. In fact, interviews classified as "complete" by regional office staff may have been reclassified as "non-respondent" or "out of scope" based on the above criteria.

By definition, these three response rates are necessarily in ascending order, from Rate 1 to Rate 3.

Table 9 summarizes the response rates of the first collection phase and the rate of out-of-scope dwellings, the rate of refusal and the rate of unoccupied dwellings.

Table 9

Response rate and other unweighted rates of the SHEU

Raw response (Rate 1)	70.7%
Intermediate response (Rate 2)	74.3%
Operational response (Rate 3)	75.5%
Rate of out-of-scope dwellings	4.8%
Rate of refusal	9.7%
Rate of unoccupied dwellings	2.5%

3.2 Data sharing

In light of the data-sharing agreement between Statistics Canada and Natural Resources Canada (NRCan), respondents were asked for their authorization to share the gathered information. The question was worded as follows:

> Statistics Canada has entered into an agreement with the Office of Energy Efficiency of NRCan to share information from this survey.
>
> NRCan will not be given your name or other identifiers. The information shared with them will contain sufficient geographic detail to allow them to analyse the data for small areas. NRCan has agreed to keep all the information provided confidential and to use it only for statistical purposes.
>
> Do you agree to allow Statistics Canada to share your information with NRCan?

An answer in the affirmative to that question authorized Statistics Canada to share the information gathered with Natural Resources Canada. Table 10 summarizes the rates of authorization for data sharing.

Table 10

Rates of authorization for data sharing

Authorization from occupant of dwelling	98.0%
Authorization from non-occupant owner	94.0%
Combined rate	93.0%

3.3 Rate of consent to contact suppliers of energy resources

Energy consumption data could be obtained in two ways: by consulting the suppliers of electricity, natural gas, fuel oil and propane, with the signed agreement of the respondent (occupant or non-occupant owner), or by entering data from bills or statements of account that the respondent provided to the interviewer for as long as was required to enter the data. The first method was encouraged in order to obtain more accurate data and to reduce the time spent with the respondent.

Table 11 summarizes the rates of consent to contact the suppliers of energy resources.

Table 11

Rates of consent to contact suppliers of energy resources

	Consent to contact all applicable suppliers	No consent given for one or more suppliers	Total	Rate of consent
Occupant	3,814	526	4,340	87.9%
Non-occupant owner	331	54	385	86.0%
Occupant and non-occupant owner	3,944	569	4,513	87.4%
Occupant and non-occupant owner:				
Electricity	4,021	477	4,498	89.4%
Natural gas	1,928	256	2,184	88.3%
Fuel oil	540	123	663	81.4%
Propane	77	21	98	78.6%

It should be noted that the above rates are based on the answers to questions CESk_Q01 and LCSk_Q01, where k = 1 (electricity), 2 (natural gas), 3 (fuel oil) or 4 (propane). Some dwellings using a given energy source may not have been asked for the correspon-ding consent, primarily because of conceptual errors in the design of the collection instrument itself. Accordingly, the rates shown are the rates of consent for the dwellings that responded to the request for consent and not for the dwellings that use the energy source in question.

In addition, once consent was given to contact a supplier, various factors may have prevented us from using the data. For example, Statistics Canada's regional offices did not receive some consent forms from the account holders,[5] and others were received but not signed (0.8 percent of the forms received: electricity, 0.7 percent; natural gas, 0.6 percent; fuel oil, 1.9 percent; propane, 0.0 percent). Lastly, we estimate that 15 percent of the consumption data requests made to the suppliers were unanswered (electricity, 9 percent; natural gas, 19 percent; fuel oil, 40 percent; propane, 36 percent).

We estimate that for the dwellings using natural gas, only 60 percent of the consumption data was obtained from the supplier. This rate is apparently higher for electricity and lower for fuel oil and propane. Moreover, the rates of data received from the suppliers – amongst dwellings that use a given energy source, before verification and imputation – follow suit, as can be seen in Table 12.

[5] The probable causes included consent questions improperly marked "yes" and consent forms left at the home for signing by someone absent at the time of the interview and not returned to Statistics Canada.

Table 12

Rates of data received from suppliers, before verification and imputation, by dwellings using the specified energy source

Energy source	Rate
Electricity	76%
Natural gas	64%
Fuel oil	48%
Propane	41%

4. Post-collection

The post-collection period includes all activities undertaken once the data have been collected. The ultimate aim of these activities is to produce a microdata file and documentation that analysts can use to extract the information they need for their work. To that end, many sectors within Statistics Canada contribute in a variety of ways. This is often the most complex phase of a survey, as every action can have an impact on the final quality of the data.

4.1 Processing the data

Processing the data involves a variety of activities with different purposes, such as:

- classifying the sample and identifying the respondents
- formatting the data
- cleaning up paths
- encoding some variables
- establishing the verification rules
- creating derived variables
- imputing

SSMD methodologists classified the sample and the respondents as described in Section 3.1. They also revised some rules for cleaning up the paths, suggested some derived variables and helped the BSMD methodologists verify and impute the data.

Quality of the data

Overall, the data gathered for the SHEU are of good quality. The reports of the interviewers and the internal consistency of the data attest to this. However, some aspects of the quality of the data and some reservations emerging during the collection and processing phases are worthy of note, as described in the following paragraphs. The reports from the various sectors of the office may reveal other limitations or difficulties inherent to the survey data.

Modification of type of dwelling between CCHS and SHEU

For 8 percent of the sample of 4,551 SHEU respondents, the type of dwelling changed after the CCHS (January to October 2003) and before the SHEU (March to June 2004). A total of 362 dwellings underwent legitimate transformations, resulting in a change in type of dwelling, or were the subject of variable responses depending on the interviewer or respondent. In particular, it seems that “duplex” and “semi-detached” types of dwellings may have been switched in some cases.

Person answering the survey questions

When we contacted the household to make an appointment for the interview, we asked that the person who paid the utility bills be there at the time of the interview in order to sign the forms authorizing us to contact suppliers. During the 1998 survey, in comparison, it seems that the appointment for the in-home interview tended toward interviewing the person with the best knowledge of the characteristics of the dwelling, including the appliances and their use, the heating system, the windows and the dwelling area. It is therefore possible that the 2004 approach resulted in interviewing individuals less familiar with some of the characteristics measured by the survey. It is probable that the effect on the quality of the answers is relatively marginal; the rate of “don’t know” answers could be an indicator of this.

Non-occupant owner, duplex or apartment

Preliminary analysis revealed that the quality of the data obtained from occupants is better than the quality of the data obtained from non-occupant owners, particularly regarding duplex dwellings and apartments located in buildings with fewer than five storeys.

Heated area

According to the report "Regional Operations Branch – Interviewers' Debriefing Summary," the dwelling area and the building area were sometimes difficult to determine, especially for tenants. The heated portion of the basement was apparently particularly difficult to measure. It is possible that the heated area of the dwelling was difficult to determine because of a lack in the definition used for "heated room." In addition, the survey was held between March and June, which means that the data on the reported heated area could have been influenced by the month in which the interview was held.

Dwelling area and building area

Inconsistencies have been detected between dwelling area and building area. It is possible that the error stems in part from the respondent's confusing the terms "logement" and "immeuble" in French or "dwelling" and "building" in English. These inconsistencies have been processed by verification and imputation.

Year built, year moved in and age of heating system

There are some inconsistencies between the year in which the dwelling was built, the year the household moved in and the age of the heating system.

Missing data

Flag variables generated by the software used to assist in data collection were used to confirm dwelling use of any one or more of the four energy sources targeted by the survey – electricity, natural gas, fuel oil and propane. For approximately 200 dwellings, the variables needed to produce these flags were empty. In these cases, it was uncertain if the dwelling used a specific energy source. In addition, the variables used to determine if the garage or basement was heated were missing for a few dozen dwellings. Because processing all of these cases would have entailed procedures too complex for the time allotted for this work, and since the impact seemed minimal, given the relatively low number of dwellings in question, these cases were declared non-respondent, and their weight was distributed among the respondent dwellings with similar characteristics.

In addition, some questions on household appliances could be answered using the "other – please specify" category without the respondent being asked which energy sources were used for the appliances. This was the case for approximately 300 dwellings, and it is therefore possible that an energy source used only for the appliance in question was not indicated. This could result in a slight underestimation of consumption, in the case of energy sources that could not be ascertained because the questions were omitted. It was recommended that we not use the dwellings affected by this problem as donors when imputing the values of the energy consumption variables.

Gas fireplaces

The survey questionnaire assumed all gas fireplaces use natural gas, while some can use propane. Survey data revealed that 100 dwellings that reported having a gas fireplace did not declare natural gas use for any other equipment type. After re-evaluation, these 100 dwellings were distributed as follows: 40 use natural gas and 60 do not (10 had already indicated they use propane, and 50 will use it from now on).

Imputation

Table 13 summarizes the rates of imputation for the SHEU variables subject to imputation.

Table 13

Rates of imputation

Variable	Description	Imputed records	Non-imputed records	Total	Rate of imputation
DFS_M01	In what year was the dwelling originally built?	558	3,993	4,551	12.26%
DFS_M02	Would you say it was built in . . . ?	31	4,520	4,551	0.68%
SOD_M02	What is the heated area of your basement in square feet/metres?	290	2,175	2,465	11.76%
SOD_M03	Would you say it is . . . ?	71	2,394	2,465	2.88%
SOG_M01	What is the size of the heated area of your indoor garage in square feet/metres?	33	32	65	50.77%
SOG_M02	Would you say it is . . . ?	14	51	65	21.54%
SOD_M06	What (excluding the basement and/or garage) is the heated area of your dwelling in square feet/metres?	563	3,988	4,551	12.37%
SOD_M07	Would you say it is . . . ?	210	4,341	4,551	4.61%
MSTOTDWE	Total dwelling area heated (square feet/metres)	646	3,905	4,551	14.19%
SBD_M01	Excluding the indoor parking, what is the heated area of your building in square feet/metres?	613	184	797	76.91%
SBD_M02	Would you say it is . . . ?	413	384	797	51.82%
MSTOTBLD	Total building area heated (square feet/metres)	615	182	797	77.16%
MELHEGJ	Electricity (GJ) heating cycle	1,132	3,418	4,550	24.88%
MELCOGJ	Electricity (GJ) air-conditioning cycle	1,141	3,409	4,550	25.08%
MELTOGJ	Electricity (GJ) total of both cycles	1,142	3,408	4,550	25.10%
MNGHEGJ	Natural gas (GJ) heating cycle	902	1,378	2,280	39.56%
MNGCOGJ	Natural gas (GJ) air-conditioning cycle	901	1,379	2,280	39.52%
MNGTOGJ	Natural gas (GJ) total of both cycles	903	1,377	2,280	39.61%
MOILTOGJ	Fuel oil total (GJ)	382	323	705	54.18%
MPROTOGJ	Propane total (GJ)	98	52	150	65.33%

It is recommended that the rate of imputation be taken into account when analysing the variables subject to imputation. In this regard, the reader is referred to “Guidelines concerning the quality of estimates” in Section 4.3.

Energy use

In addition to having undergone high rates of imputation, the energy use variables present another difficulty. Based on a number of verifications made by the project manager, it was noted that consumption data could be of lower quality in the case of duplexes and “apartments in a building with fewer than five storeys.” For these dwellings, it seems that the concept “proportion of the building’s consumption attributable to the dwelling” was not very successful. Therefore, the consumption data of dwellings resulting from the application of this proportion to the building’s consumption data could have been incorrectly estimated. The approach in question had not been tested prior to the survey, which could explain its relative lack of success. In addition, the ambiguity between the terms “dwelling” and “building” in English and between “logement” and “immeuble” in French could have contributed to the inaccuracy of the reported proportions.

4.2 Weighting procedures

The weighting of the SHEU sample involved 11 steps:

1. Adjustment of the CCHS subweight to account for the undercoverage of the sampling frame
2. Selection of the SHEU sample
3. Adjustment to account for multiple dwellings
4. Adjustment to account for dwellings whose address was not confirmed
5. Adjustment to account for dwellings whose occupation was not confirmed
6. Adjustment to account for type-1 full non-responses (no data gathered)
7. Adjustment to account for type-2 full non-responses (households who moved into the selected dwelling in 2004)
8. Adjustment to account for type-1 partial non-responses (data on the heating system and hot water tank, used for determining the energy sources used by the dwelling, were missing)
9. Adjustment to account for type-2 partial non-responses (other cases of partial non-response)
10. Initial calibration of weights to produce estimates consistent with CCHS estimates, with two margins: first, the number of dwellings in scope, by province; and second, the number of dwellings based on certain groupings of dwelling types and based on a selected geographic level (national or regional)
11. Second calibration of weights to produce estimates consistent with LFS estimates in 10 domains: grouped type of dwelling (single detached dwellings vs. all others) for each of the usual five infranational regions (Atlantic provinces, Quebec, Ontario, Prairie provinces, British Columbia)

4.3 Variance estimation

Use of Bootvar software

The bootstrap method was used for estimating the SHEU variance. Basically, the 500 bootstrap weights of the CCHS were subjected to the 11 steps of the SHEU weighting procedure, as described in Section 4.2. The resulting bootstrap weights were then used for estimating the SHEU variance. The Bootvar software and its documentation accompany the SHEU microdata file so that the variance estimates can be produced.

Coefficients of variation tables

In keeping with the tradition of the previous Surveys of Household Energy Use, coefficients of variation tables have been created for the usual five infranational regions and for the 10 provinces as a whole. The estimates provided in these tables are less precise than those obtained with the bootstrap method. The tables are based on an overall design effect by region corresponding to the third quartile of the design effects calculated using Bootvar for 100 variables representative of the SHEU.

Guidelines concerning the quality of estimates

The coefficient of variation of an estimate is obtained with the Bootvar software. In the case of variables that were not imputed, the guidelines in Table 14 apply.

Table 14

Guidelines concerning the quality of the estimate in the case of non-imputed variables

Level of quality of the estimate	Guideline
Acceptable	The estimates are based on a sample of 30 or more units and present low coefficients of variation, between 0.0 and 16.5 percent. Acceptable estimates are marked with the letter *A*.
Use with caution	The estimates are based on a sample of 30 or more units and present high coefficients of variation, between 16.6 and 33.3 percent. Such estimates are marked with the letter *M*.
Too unreliable to be published	The estimates are based on a sample with fewer than 30 units, or they present very high coefficients of variation, greater than 33.3 percent. Statistics Canada recommends that such estimates not be released as their quality is unacceptable. Unreliable estimates are marked with the letter *U* and are accompanied by the following warning: “Estimates marked by the letter *U* do not meet Statistics Canada’s quality standards. Any conclusion based on this data is not dependable and is most likely invalid.”

In the case of imputed variables, the procedure to follow for determining the level of quality of the estimate is as follows:

1. Calculate the coefficient of variation (CV) of the estimate with the Bootvar program. Include reported values and imputed values in this estimate and in the CV calculation. A value is deemed reported if its imputation flag equals 3 (not imputed). A value is considered imputed when its imputation flag is 1 (imputed deterministically) or 2 (imputed from donor).

2. Calculate the rate of imputation of the estimate based on the variable's imputation flag: rate of imputation = i/n, where i is the number of imputed values and n is the sum of the number of reported values plus the number of imputed values.

3. Calculate the "adjusted CV" using the CV from Bootvar and the rate of imputation, as follows:

$$\text{CV\_adjusted} = \sqrt{\frac{n}{r}}\ \text{CV} = \frac{\text{CV}}{\sqrt{1 - \text{Rate of imputation}}}$$

   where r is the number of reported values and n is the sum of the number of reported values plus the number of imputed values. Round the adjusted CV to the nearest tenth of a percent (for example, round 16.58 percent to 16.6 percent).

4. Apply the guidelines described in Table 14 by replacing the term "sample" (which, in the case of imputed variables, equals all reported values plus imputed values, represented here by n) with the term "sample restricted to reported values" (which equals the number of all reported values, represented here by r) and by replacing the expression "coefficient of variation" with "adjusted coefficient of variation" (as defined in Step 3 above).

APPENDIX B

Glossary

Glossary

Air conditioning: Set of operations aimed at comfort by creating and maintaining predetermined conditions of temperature, relative humidity, speed and purity of air.

Air exchanger: Device allowing the transfer of air from one area to another.

Apartment: Part of a building containing several connecting rooms that form a dwelling unit. This type of dwelling includes units found in residential buildings or residential hotels; apartments in duplexes and triplexes (where each unit takes up one floor); apartments in houses where the structure has been modified; dwellings in business establishments; dwellings of caretakers in schools, churches, warehouses and elsewhere; and private spaces for employees of hospitals and other kinds of institutions. SHEU–2003 only includes apartments located within a building with fewer than five storeys.

Appliance: Device used in a house during the year. Appliances at the disposal of the head of the household for regular use are to be counted. Appliances that are owned by the household but are not used are not to be counted, except for air-conditioning units. An appliance that is temporarily inoperable, but which is generally used, is included if a serviceperson has been called or if it has been transported to a repair shop.

Attic: Uppermost storey of a dwelling, below the roof, used more for storage purposes than for living purposes.

Automatic defrost: Automatic elimination of frost deposits that may have formed on the inside walls of a freezer.

Basement: Usable part of a building, which is located partially or completely beneath the outside ground level.

Btu (British thermal unit): The quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit.

Built-in oven: Domestic appliance placed in a closed compartment with a supply of heat, used for cooking food. In contrast to the kitchen stove, the built-in oven cannot be moved and is not equipped with surface heating elements (burners).

Ceiling fan: Motorized fan installed on the ceiling and used to force the circulation of air in a given direction.

Central ventilation system (air exchanger): Device that takes stale air from inside a dwelling and exchanges it with fresh air from outside a dwelling.

Clothes dryer: Appliance used to dry clothing by evaporation accelerated by applying heat and rapid air movement. The air is usually heated by electricity or natural gas.

Clothes washer: An appliance for washing laundry, composed of a washtub, an agitator and a system for draining used water. An opening at the top or front of the appliance provides access to the washtub.

Compact fluorescent lights: General term applied to smaller-diameter fluorescent lights.

Compact stereo: A compact stereo is a one-component stereo system that is not capable of being easily carried or moved about because of its size or design (no built-in handles or carrying straps).

Component stereo system: A component stereo system has two or more components. Each component has its own electrical plug. The components and speakers operate together to produce sound. Components may include an amplifier, audio-video receiver, CD player, tape player, record player and radio tuner.

Condensation: Physical reaction in which water vapour molecules join together to form water droplets that attach themselves to the interior surface of a window.

Condensing clothes dryer: A clothes dryer where all the steam created by the drying process is cooled and condensed back into water. This water is then collected in a reservoir inside the machine. It is a ventless clothes dryer.

Cooktop: Appliance not attached to an oven, used for cooking food (the kitchen stove is a one-piece appliance containing an oven and a cooktop).

Crawl space: Ventilated open space between the ground and the lowest storey of a building, of a height sufficient for crawling.

Dishwasher: An appliance designed to wash dishes automatically. Water is sprayed over dishes either by fixed jets aimed at a rotating basket or by rotating jets.

Double-paned window: Window containing two panes of glass separated by an air space.

Double/row house: House connected to at least one other dwelling, which together form a building. For SHEU–2003, duplexes (two dwellings one above the other, not attached to any other structure) are included in this category.

Dwelling: A living space that is structurally separate from others, with a private entry accessible from the outside of the building or from a stairwell or common corridor.

Electric baseboard: Electric heat-emitting appliance located at ground (or ceiling) level. This appliance may be made of cast iron or flanges.

Electricity: Electric energy measured by a meter, distributed by a public utility company to a dwelling through overhead or underground lines.

Electric radiant heating: Radiant heat sources warm objects within their range without necessarily having to heat up the surrounding space. Two types of electric radiant heating are portable infrared heaters and electric radiant heating cables installed in a floor or ceiling.

Energy intensity: Total energy consumption of a dwelling divided by the number of heated units of floor area (excluding the basement and the garage). In this document, energy intensity is expressed in gigajoules per square metre (GJ/m^2).

Energy source: Type of energy used by a household. The term includes all substances that yield heat or power, including petroleum, natural gas, renewable energy and electricity.

ENERGY STAR® qualified product: As an international symbol of energy efficiency, the ENERGY STAR mark helps consumers identify which appliances on the market are the most energy efficient in their class. Administered in Canada by Natural Resources Canada, the ENERGY STAR symbol is used mainly to identify products offering premium performance levels in energy efficiency. The ENERGY STAR symbol can be found on product packaging, literature and advertising and on the products themselves. In some cases, you may also find it on the EnerGuide label. The following criteria are used to determine if an appliance qualifies for the ENERGY STAR mark.

- A standard-size **refrigerator** must exceed the minimum energy performance standard established by the Government of Canada by at least 10 percent in 2003, and at least 15 percent in 2004. A standard-size **freezer** must, in 2003, exceed these standards by at least 10 percent. Compact refrigerators and freezers must exceed these same standards by at least 20 percent.
- A standard-size **dishwasher** must exceed the minimum energy performance standards established by the Government of Canada by at least 25 percent in 2003. Only standard-size dishwashers can qualify for the ENERGY STAR mark.
- A **clothes washer** must use from 35 to 50 percent less water and at least 50 percent less energy per load than conventional washers.

- A **television** must use 3 watts or less when turned off, i.e., use 75 percent less energy than conventional televisions, which consume up to 12 watts when turned off.
- A **video cassette recorder** must use 4 watts or less when turned off, i.e., use 70 percent less energy than conventional video cassette recorders, which consume up to 13 watts when turned off.
- A **DVD player** must use 3 watts or less when turned off, i.e., use 75 percent less energy than conventional DVD players, which consume up to 10 watts when turned off.
- A **system stereo** must use 2 watts or less when turned off, i.e., use 70 percent less energy than conventional stereo systems, which consume up to 7 watts when turned off.
- A **room air conditioner** must exceed the minimum energy performance standards established by the Government of Canada by at least 10 percent in 2003. A **central air conditioner** must exceed these standards by 20 percent.
- A **forced-air furnace** must have an annual fuel utilization efficiency rating of 90 or higher. A **furnace (boiler) with hot water or steam radiators** must have an annual fuel utilization efficiency rating of 85 or higher.

Fireplace: Space in a wall or chimney mantle in which a heating apparatus can be installed and equipped with a chimney flue.

Foundation: Structure of masonry, reinforced concrete or steel that supports and immobilizes support units and structural members of the frame. It is designed to distribute all loads that are transmitted to it toward or under the ground judiciously. The word “foundation” includes basement, crawl space and slab on grade (concrete).

Freezer: Appliance designed to freeze products at a temperature of approximately –15°C. The process of freezing involves removing heat from products to lower their temperature to a point where most of the water they contain is solidified. This is a separate appliance and is not part of a refrigerator. It is built as either a vertical model (with a door that opens outward) or a chest-style model (with a lid).

Fuel oil: Somewhat viscous (thick), dark brown or black, combustible liquid made from petroleum.

Full cord: English standard measure equivalent to a pile of wood measuring 1.2 m 3 1.2 m 3 2.4 m, or 3.4 m^3 (128 cu. ft.).

Furnace (boiler) with hot water or steam radiators: A heating system with a pump that distributes water heated by a boiler through a network of pipes in the dwelling to radiators in the rooms. The radiators release the heat from the water into the room.

Furnace with forced air (hot air vents): A furnace that distributes heat by using a motor-driven fan to circulate heated air through the duct system of a dwelling. The heated air is delivered to different rooms through air vents.

Garage: Generally enclosed covered space designed to shelter vehicles other than horse-drawn vehicles.

Gigajoule (GJ): Unit of measure for energy consumption equal to 1 billion joules.

Halogen light bulbs: Incandescent lights containing halogen gases, which burn very hot while providing an intense white light.

Heated floor area of dwelling: All space within the exterior walls of a dwelling that is heated, excluding garage and basement, if any.

Heat pump: Heating and cooling unit that draws heat from an outdoor source and transports it to an indoor space for heating purposes, or does the inverse for cooling purposes.

High efficiency back-up furnace: A furnace with additional heat exchange surfaces used to supplement a heat pump. These extract most of the heat remaining in the combustion by-products through a condensing heat-exchange process.

Hot water tank: A thermally insulated tank with automatic controls designed to produce and hold hot water.

House: Building designed for human habitation.

Household: Person or group of persons who occupy a dwelling. The number of households, therefore, is equal to the number of dwellings occupied. The person or persons who occupy a private dwelling form a private household.

Household income: Total income of all members of the household in 2003, from all sources, before taxes and other deductions.

Icemaker: Compact device within a refrigerator that automatically produces a relatively small quantity of ice.

Insulation blanket: Insulation that covers a hot water tank in order to conserve energy.

Louvred unit: A window-mounted air-conditioning unit that has accordion-style or louvred side panels installed between the unit and the window frame to prevent drafts.

Low-E coating: Low-E (low-emissivity) coatings are highly reflective, transparent coatings applied to windowpanes to slow heat loss.

Microwave oven: An appliance that emits electromagnetic waves capable of agitating water molecules contained in food. The repeated friction of these molecules raises the temperature, enabling the food to cook rapidly.

Mobile home: Mobile dwelling designed and built to be transported by road on its own frame to a location where it may be placed on a temporary foundation, such as concrete blocks, pillars or some other specifically designed structure. It must be able to be moved again to another location, as required.

Moisture detector: A moisture detector is a sensor in a clothes dryer used to check the amount of moisture in the clothes and to terminate the dryer cycle automatically when the clothes are dry.

Natural gas: A gaseous mixture of saturated hydrocarbons that is found in underground deposits either alone or with petroleum. It is delivered directly to buildings by pipelines.

Non-louvred unit: Wall-mounted air-conditioning unit that does not have accordion-style or louvred side panels around it.

Non-respondent: A dwelling that did not provide sufficient data or an authorization for data sharing.

Ordinary (incandescent) light bulb: The standard incandescent light bulb is the original and most common type of bulb used in the house.

Outdoor lights with motion detector: Outdoor lighting fixtures that turn on when the sensor detects movement and turn off automatically after a set period of time.

Outside walls: Walls that communicate directly to the outside of the house. This excludes walls that are shared between row houses or double houses.

Pillars: Wood, concrete or metal columns that are driven into the ground and used to support a building and prevent it from sinking into the ground.

Pilot light (gas fireplace): Small flame within a gas-burning or oil-burning unit that is allowed to burn continually to ensure automatic ignition of the unit.

Portable electric heater: Heating unit that can be easily transported. The source of heat is electrical resistance.

Portable stereo: A stereo that is capable of being easily carried or moved about (using built-in handles or carrying straps). A portable stereo is also a one-component stereo system. Walkmans and MP3 players are not considered to be portable stereos.

Programmable thermostat: Device that automatically controls the amount of heat or cold distributed within a room by reacting to room temperature. The programmable thermostat makes it possible to set the desired temperature of a room according to the time of the day.

Propane: A saturated, aliphatic, linear-chain hydrocarbon found in natural gas and petroleum and widely used as a fuel.

Refrigerator: A movable chest in which the temperature can be reduced and controlled for the preservation of refrigerated foods. Most refrigerators are equipped with a second compartment for freezing foods.

Respondent: A dwelling that provided sufficient data and an authorization for data sharing.

Retrofit: Improvement of efficiency of energy-consuming appliances or thermal characteristics of a building.

Rural area: Any area located outside an urban area is considered to be part of a rural area.

Single detached house: House containing a single dwelling unit entirely separate from any other building or structure, generally known as a single-family house.

Single-paned window: Window containing a single pane of glass.

Slab on grade (concrete slab): Rigid, horizontal (or almost horizontal) concrete structure, much wider than it is thick, upon which a house is built.

Space heating: Use of mechanical equipment for heating all or part of a building, including all equipment for space heating plus all equipment for supplementary heating.

Standard socket: An opening or cavity into which the base of a standard (incandescent) light bulb is designed to fit. The socket provides the bulb with electricity.

Storey: The space contained between two consecutive floors, or between a floor and a roof.

Storm windows: Storm windows fit into, or over, primary windows and are used to minimize drafts due to air leakage. Storm windows can be installed on the inside or the outside, and they can be permanent, seasonal or temporary.

Stove or kitchen stove: A single-unit appliance used to cook food, combining a cooking surface and an oven. The stove may be heated by wood, coal, oil, gas or electricity, or by different combinations thereof (such as a stove using both natural gas and electricity).

Supplementary heating: Heating system that can be used in addition to a main heating system, as desired, and that is flexible enough to respond to rapid variations in heating needs.

Swimming pool: Any basin or tank that holds water and that is sufficiently large for swimming.

Thermal envelope: The facing materials that form the shell of a building, including walls, ceilings, roof, basement walls, windows and doors.

Triple-paned window: Window containing three panes of glass separated by air spaces.

Unit out of scope: A dwelling whose type is incompatible with the survey, i.e., all dwellings that are located in a First Nation community, on a military base or in a business or institution; vacant, demolished or under construction; seasonal or secondary residences; or occupied by individuals who work full-time within the Canadian Armed Forces.

Urban area: An area with a population of at least 1,000 inhabitants and a population density of at least 400 inhabitants per square kilometre, as determined in the last census.

Water devices: Water devices include hot water tanks, water-saving shower heads, and tap attachments.

Water heater with add-on insulation: A water heater with insulation, such as an insulation blanket, placed around it in order to save energy (keep the heat in). This insulation is not necessary for the water heater to work.

Water heating: The use of energy to heat running water and cooking water, plus the use of energy by auxiliary water heating appliances to heat water for various non-cooking uses (bathing, cleaning).

Window: A construction unit set into a space (vertical or practically vertical) within a wall or inclined roof to allow light, and possibly air, to enter.

Wood: A product manufactured from trees.

Wood stove: An enclosed heating unit in which wood is burned.

APPENDIX C

Questionnaire

Section: Entry Section

Is this dwelling owned by a member of this household?

1	Yes
2	No
8	Refusal

Is this part of a condominium?

1	Yes
2	No
6	Valid skip

Section: AP – Appliances Probe

Were there any major appliances already in your dwelling when you moved in?

1	Yes
2	No
7	Don't know

Which appliances?

1	Refrigerator
2	Freezer
3	Regular stove or built-in oven with separate cooktop
4	Microwave oven
5	Dishwasher
6	Washing machine
7	Clothes dryer
8	Other
9	Valid skip
10	Don't know
11	Not stated

Section: FRG – Fridges

How many refrigerators do you use?

0	0
1	1
2	2
3	3 or more

What kind of doors does your (main) refrigerator have?

1	Top and bottom doors with freezer on top
2	Top and bottom doors with freezer on bottom
3	Single door
4	Side-by-side doors
5	Three doors
6	Valid skip

What is the size of your (main) refrigerator?

1	Compact (less than 7.75 cubic feet)
2	Small (7.76 to 12.4 cubic feet)
3	Medium (12.5 to 16.4 cubic feet)
4	Large (16.5 to 20.0 cubic feet)
5	Very large (more than 20 cubic feet)
6	Valid skip
7	Don't know

Is the height of your (main) refrigerator less than 36 inches (91 centimetres)?

1	Yes
2	No
6	Valid skip

Does your (main) refrigerator automatically defrost?

1	Yes
2	No
6	Valid skip
7	Don't know

Is there an automatic ice maker in the door of your (main) refrigerator?

1	Yes
2	No
6	Valid skip

How old is your (main) refrigerator?

01 : 50	Age of main refrigerator (years)
96	Valid skip
97	Don't know
98	Refusal

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

Is your (main) refrigerator an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Approximately how old was your previous refrigerator when it was replaced with this one?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
08	This is the original/first refrigerator
96	Valid skip
97	Don't know
98	Refusal

What did you do with your old refrigerator?

1	Kept it at home and plugged in all year
2	Kept it at home and plugged in when needed
3	Disposed of it, refrigerator no longer working
4	Other
6	Valid skip
7	Don't know
9	Not stated

What kind of doors does your second refrigerator have?

1	Top and bottom doors with freezer on top
2	Top and bottom doors with freezer on bottom
3	Single door
4	Side-by-side doors
5	Three doors
6	Valid skip
9	Not stated

What is the size of your second refrigerator?

1	Compact (less than 7.75 cubic feet)
2	Small (7.76 to 12.4 cubic feet)
3	Medium (12.5 to 16.4 cubic feet)
4	Large (16.5 to 20 cubic feet)
5	Very large (more than 20 cubic feet)
6	Valid skip
7	Don't know
9	Not stated

Is the height of your second refrigerator less than 36 inches (91 centimetres)?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Does your second refrigerator automatically defrost?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Is there an automatic ice maker in the door of your second refrigerator?

1	Yes
2	No
6	Valid skip
9	Not stated

How old is your second refrigerator?

01 : 50	Age of second refrigerator (years)
96	Valid skip
97	Don't know
99	Not stated

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

Section: FRZ – Freezer

Excluding the freezer(s) in your refrigerator(s), how many freezers do you use?

0	0
1	1
2	2
3	3 or more

Is your (main) freezer...?

1	A chest type (top opening)
2	An upright type (front opening)
6	Valid skip
7	Don't know
8	Refusal

Does your (main) freezer...?

1	Automatically defrost
2	Manually defrost
6	Valid skip
7	Don't know

How old is your (main) freezer?

01 : 50	Age of main freezer (years)
96	Valid skip
97	Don't know
98	Refusal

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

Is your (main) freezer an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

What is the size of your (main) freezer?

1	Very small (less than 7.0 cubic feet)
2	Small (7.1 to 13.9 cubic feet)
3	Medium (14.0 to 17.9 cubic feet)
4	Large (18.0 to 22.9 cubic feet)
5	Very large (23 cubic feet and more)
6	Valid skip
7	Don't know

Was your previous freezer still working when you replaced it with this one?

1	Yes
2	No
3	This is the original/first freezer
6	Valid skip
7	Don't know

Approximately how old was your previous freezer when you replaced it with this one?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Section: STV – Stoves

Do you use a regular stove or a built-in oven with a separate cooktop?

1	Regular stove (range, free-standing)
2	Built-in oven with a separate cooktop
3	Other – Specify

What source of energy does your separate cooktop use?

1	Electricity
2	Natural gas
3	Other
6	Valid skip

What source of energy does your built-in oven / regular stove use?

01	Electricity
02	Natural gas
03	Oil
04	Wood
05	Propane
06	Electricity and natural gas
96	Valid skip

Is your built-in oven / regular stove self-cleaning?

1	Yes
2	No
6	Valid skip
7	Don't know

How old is your built-in oven / regular stove?

01 : 50	Age of stove (years)
96	Valid skip
97	Don't know
98	Refusal

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

How old is your separate cooktop?

01 : 50	Age – separate cooktop (years)
96	Valid skip
97	Don't know

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know

In an average week, how often do you use your built-in oven with a separate cooktop / regular stove?

01	Three or more times a day
02	Two times a day
03	Once a day
04	A few times each week
05	Once a week
06	Less than once a week
07	Never
96	Valid skip

Section: MCW – Microwaves

Do you use a microwave oven?

1	Yes
2	No

In an average week, how many minutes do you use your microwave oven. Would you say...?

01	Less than 5 minutes
02	5 to 15 minutes
03	16 to 30 minutes
04	31 to 60 minutes
05	61 minutes to 2 hours
06	More than 2 hours
96	Valid skip
97	Don't know

Section: DWS – Dishwashers

Do you use a dishwasher?

1	Yes
2	No

Is it a compact or a standard-size dishwasher?

1	Compact (mini – exterior width less than 56 centimetres / 22 inches)
2	Standard (full size – exterior width greater than or equal to 56 centimetres / 22 inches)
6	Valid skip

How old is your dishwasher?

01 : 33	Age – dishwasher (years)
96	Valid skip
97	Don't know
98	Refusal

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

Is your dishwasher an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Do you rinse off the dishes before putting them in the dishwasher?

1	Most of the time
2	Sometimes
3	Rarely
4	Never
6	Valid skip
7	Don't know
8	Refusal

Do you usually dry the dishes with the...?

1	Heat on (hot air)
2	Heat off (door closed)
3	Door open (dishes dry naturally)
6	Valid skip
7	Don't know
8	Refusal

In an average week, how many loads of dishes do you do?

00 : 21	Number of times dishwasher loaded per week
96	Valid skip
97	Don't know
98	Refusal

Was your previous dishwasher still working when you replaced it with this one?

1	Yes
2	No
3	This is the original/first dishwasher
6	Valid skip
7	Don't know
8	Refusal

Approximately how old was your previous dishwasher when you replaced it with this one?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

Section: WSH – Washer

Do you use a washing machine (in your dwelling)?

1	Yes
2	No
8	Refusal

What type of washing machine do you use?

1	Automatic washer
2	Washer/dryer combination

3	Other – Specify
6	Valid skip
9	Not stated

Is it a front-loading or a top-loading washing machine?

1	Front-loading
2	Top-loading
6	Valid skip
9	Not stated

What size is your washing machine?

1	Mini (compact – less than 45 litres / 10 gallons)
2	Standard (full size – greater than or equal to 45 litres / 10 gallons)
6	Valid skip
7	Don't know
9	Not stated

How old is your washing machine?

01 : 40	Age – washing machine (years)
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

Is your washing machine an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

What water temperature do you use for most of your washing?

1	Hot
2	Warm
3	Cold
6	Valid skip
7	Don't know
9	Not stated

What water temperature do you use for most of your rinsing?

1	Hot
2	Warm
3	Cold
6	Valid skip
7	Don't know
9	Not stated

In an average week during the winter, how many loads of laundry do you wash?

00 : 40	Winter – loads of laundry per week
96	Valid skip
97	Don't know
99	Not stated

In an average week during the summer, how many loads of laundry do you wash?

00 : 40	Summer – loads of laundry per week
96	Valid skip
97	Don't know
99	Not stated

Was your previous washing machine still working when you replaced it with this one?

1	Yes
2	No
3	This is the original/first washing machine
6	Valid skip
7	Don't know
9	Not stated

Approximately how old was your previous washing machine when you replaced it with this one?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Section: DRY – Dryer

Do you use a clothes dryer (in your dwelling)?

1	Yes
2	No

Is your clothes dryer a condensing clothes dryer, that is, not vented to the outside?

1	Yes
2	No
6	Valid skip
7	Don't know

What size is your clothes dryer?

1	Compact (less than 125 litres / 28 gallons capacity)
2	Standard (greater than or equal to 125 litres / 28 gallons capacity)
6	Valid skip

How old is your clothes dryer?

01 : 40	Age – clothes dryer (years)
96	Valid skip
97	Don't know

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know

Does your clothes dryer have a moisture detector?

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal

In an average week during the winter, how many loads of laundry do you dry in the clothes dryer?

00 : 40	Winter – loads dried per week
96	Valid skip
97	Don't know

In an average week during the summer, how many loads of laundry do you dry in the clothes dryer?

00 : 36	Summer – loads dried per week
96	Valid skip
97	Don't know
98	Refusal

Was your previous clothes dryer still working when you replaced it with this one?

1	Yes
2	No
3	This is the original/first clothes dryer
6	Valid skip
7	Don't know

Approximately, how old was your previous clothes dryer when you replaced it with this one?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Section: PC – Personal Computer

How many personal computers do you use?

00 : 08	Number of personal computers
98	Refusal

In an average week, how many hours do you have your (most frequently used) personal computer turned on?

000 : 168	Computer – hours turned on per week
996	Valid skip
997	Don't know
999	Not stated

In an average week, how many hours do you use your (most frequently used) personal computer? Please include the time used for downloading.

000 : 168	Computer – hours used per week
996	Valid skip
997	Don't know
998	Refusal
999	Not stated

How old is your (most frequently used) personal computer?

01 : 28	Age – personal computer (years)
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Would you say it is ...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

Section: VP – Video Probe

Do you use
. . . a television set?

1	Yes
2	No

Do you use
. . . a VCR?
. . . a DVD player? Please exclude video game systems that can play DVDs.
. . . a video game system that requires an electrical outlet?
. . . a satellite dish?

1	Yes
2	No
6	Valid skip

Section: TV – Television

How many television sets do you use?

01 : 08	Television – number used
96	Valid skip

In an average week, how many hours do you have your (most frequently used) television set turned on?

000 : 168	Television – hours turned on per week
996	Valid skip
997	Don't know

How old is your (most frequently used) television set?

01 : 41	Age – television (years)
96	Valid skip
97	Don't know
98	Refusal

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

Is your (most frequently used) television set an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

Section: VCR – Videocassette Recorder

How many VCRs do you use?

01 : 08	VCR – number used
96	Valid skip

In an average week, how many hours do you have your (most frequently used) VCR turned on?

000 : 168	VCR – hours turned on per week
996	Valid skip
997	Don't know

How old is your (most frequently used) VCR?

01 : 30	Age – VCR (years)
96	Valid skip
97	Don't know
98	Refusal

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

Is your (most frequently used) VCR an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Section: DVD – DVD Player

How many DVD players do you use? Please exclude video game systems that can play DVDs.

01 : 05	DVD player – number used
96	Valid skip
97	Don't know

In an average week, how many hours do you have your (most frequently used) DVD player turned on?

000 : 168	DVD player – hours turned on per week
996	Valid skip
997	Don't know
999	Not stated

How old is your (most frequently used) DVD player?

01 : 08	Age – DVD player (years)
96	Valid skip
97	Don't know
99	Not stated

Would you say it is...?

1	1 year or less
2	2 to 3 years
3	4 to 5 years
4	6 years or more
6	Valid skip
7	Don't know
9	Not stated

Is your (most frequently used) DVD player an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

Section: VG – Video Game Systems

How many video game systems that require an electrical outlet do you use?

01 : 07	Video game systems – number used
96	Valid skip
97	Don't know

Section: SAT – Satellite Dishes

How many satellite dishes do you use?

01 : 04	Satellite dishes – number used
96	Valid skip

Section: STE – Stereos

How many component stereo systems do you use?

00 : 07	Component stereo systems – number used
97	Don't know

How many compact and portable stereos (boom boxes) do you use?

00 : 07	Compact stereos – number used

In an average week, how many hours do you use your (most frequently used) stereo (system)?

000 : 168	Stereo system – hours used per week
996	Valid skip
997	Don't know

How old is your (most frequently used) stereo (system)?

01 : 30	Age – stereo system (years)
96	Valid skip
97	Don't know

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know

Is your (most frequently used) stereo (system) an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

Section: PHO – Phones

How many telephones that require an electrical outlet do you use (electricity and a telephone jack)?

00 : 08	Telephones – number used

How old is your (most frequently used) telephone that requires an electrical outlet?

01 : 30	Age – telephone (years)
96	Valid skip
97	Don't know
98	Refusal

Would you say it is...?

01	3 years or less
02	4 to 5 years
03	6 to 10 years
04	11 to 15 years
05	16 to 20 years
06	21 to 25 years
07	26 years or more
96	Valid skip
97	Don't know
99	Not stated

How many answering machines do you use? Please exclude voice mail services.

00 : 05	Answering machines – number used

Section: WTC – Water Cooler

Do you use a water cooler?

1	Yes
2	No

Section: HNF – Heat Pumps and Furnaces

In 2003, was the unit that supplied the heat to your dwelling a central unit for your building or was it a unit specifically used by your dwelling only?

1	Central unit
2	Dwelling unit
6	Valid skip
7	Don't know

In 2003, did you use a heat pump?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Was your heat pump an air source or ground source (earth energy system)?

1	Air source
2	Ground source
6	Valid skip
7	Don't know
9	Not stated

How old is your heat pump?

01 : 30	Age – heat pump (years)
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Would you say it is...?

01	3 years old or less
02	4 to 5 years old
03	6 to 10 years old
04	11 to 15 years old
05	16 to 20 years old
06	21 to 25 years old
07	26 years old or more
08	Unsure; was there when moved in
96	Valid skip
99	Not stated

In 2003, did you use a back-up furnace with your heat pump?

1	Yes
2	No
6	Valid skip
9	Not stated

What source of energy did the back-up furnace use? Please exclude the energy used for running the fan.

01	Electricity
02	Natural gas
03	Oil
04	Wood
05	Propane
06	Other – Specify
96	Valid skip
99	Not stated

How old is your back-up furnace?

01 : 45	Age – back-up furnace (years)
96	Valid skip
97	Don't know
99	Not stated

Would you say it is...?

01	3 years old or less
02	4 to 5 years old
03	6 to 10 years old
04	11 to 15 years old
05	16 to 20 years old
06	21 to 25 years old
07	26 years old or more
08	Unsure; was there when moved in
96	Valid skip
99	Not stated

Is your back-up furnace an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Was it a high-efficiency back-up furnace? A high-efficiency furnace has a plastic pipe that exhausts to the outside. It is also known as a condensing furnace.

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

In 2003, what type of heating equipment provided most of the heat for your dwelling?

01	Furnace with forced air (hot air vents)
02	Electric baseboards
03	Heating stove (burning wood, pellets, corn, coal, etc.)
04	Furnace (boiler) with hot water or steam radiators
05	Electric radiant heating
06	Other equipment – Specify
96	Valid skip
97	Don't know
99	Not stated

How old is your heating equipment?

001 : 080	Age – heating equipment (years)
996	Valid skip
997	Don't know
998	Refusal
999	Not stated

Would you say it is...?

01	3 years old or less
02	4 to 5 years old
03	6 to 10 years old
04	11 to 15 years old
05	16 to 20 years old
06	21 to 25 years old
07	26 years old or more
08	Unsure; was there when moved in
96	Valid skip
97	Don't know
99	Not stated

Is your furnace an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Did your furnace / heating stove use one or two sources of energy? Please exclude the energy used for running the fan.

1	1
2	2
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

What source of energy did your furnace / heating stove use?

01	Electricity
02	Natural gas
03	Oil
04	Wood
05	Propane
06	Other – Specify
96	Valid skip
99	Not stated

What sources of energy did your furnace / heating stove use?

1	Electricity and oil
2	Electricity and natural gas
3	Wood and oil
4	Wood and electricity
5	Other – Specify

6	Valid skip
7	Don't know
9	Not stated

Was it a high-efficiency furnace? A high-efficiency furnace has a plastic pipe that exhausts to the outside. It is also known as a condensing furnace.

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

Section: FP – Fireplaces

In 2003, how many wood-burning fireplaces did you have in your dwelling?

00 : 04	Wood fireplaces – number in dwelling

How old is your (most frequently used) wood-burning fireplace...?

1	Less than 4 years old
2	4 to 6 years old
3	7 to 10 years old
4	11 years old or more
5	Unsure; was there when moved in
6	Valid skip
7	Don't know
8	Refusal

Did your (most frequently used) wood-burning fireplace have glass doors?

1	Yes
2	No
6	Valid skip

In 2003, how many gas-burning fireplaces did you have in your dwelling?

00 : 04	Gas fireplaces – number in dwelling

How old is your (most frequently used) gas-burning fireplace?

1	Less than 4 years old
2	4 to 6 years old
3	7 to 10 years old
4	11 years old or more
5	Unsure; was there when moved in
6	Valid skip
7	Don't know

Did your (most frequently used) gas-burning fireplace have glass doors?

1	Yes
2	No
6	Valid skip

Was this gas-burning fireplace installed where a wood-burning fireplace previously existed?

1	Yes
2	No
6	Valid skip
7	Don't know

Did this gas-burning fireplace have a pilot light?

1	Yes
2	No
6	Valid skip
7	Don't know

During the summer, did you turn the pilot light off?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Did your (most frequently used) gas-burning fireplace vent its exhaust out the chimney or out the side wall (direct vent)?

1	Out the chimney
2	Out the side wall (direct vent)
6	Valid skip
7	Don't know

During an average heating season, how often did you use your (most frequently used) gas-burning fireplace?

1	Every day
2	Several times a week
3	A few times a week
4	A few times a month
5	Never
6	Valid skip
7	Don't know

Section: OH – Other Heating

In 2003, in addition to your heat pump (with back-up furnace) / furnace / main heating, did your household use any other supplementary heating equipment?

1	Yes
2	No

What type of supplementary heating equipment did you use most often?

1	Electric baseboards
2	Portable electric heater
3	Wood stove
4	Furnace
5	Other – Specify
6	Valid skip

What energy source did your (supplementary) furnace use? Please exclude the energy used for running the fan.

01	Electricity
02	Natural gas
03	Oil
04	Wood
05	Propane
06	Other source
96	Valid skip

In an average week during the heating season, how many hours did you use the supplementary heating?

000 : 168	Heating – hours used per week
996	Valid skip
997	Don't know

In 2003, how many cords of wood did you use?

00	0
01	1 or less
02	2
03	3
04	4
05	5
06	6 or more
07	Used wood that cannot be measured in cords
96	Valid skip
97	Don't know

What type of cord was it?

1	Face or stove cord (approximately 16 inches 3 8 feet 3 4 feet)
2	Full or bush cord (4 feet 3 8 feet 3 4 feet)
6	Valid skip
7	Don't know
9	Not stated

During the heating season, at what temperature did you usually maintain the largest heated area in your dwelling in the daytime? (roughly 6 a.m. to 4 p.m.)
. . . in the evening? (roughly 4 p.m. to 11 p.m.)
. . . at night? (roughly 11 p.m. to 6 a.m.)

16	16°C or less (61°F or less)
17	17°C (62°F–63°F)
18	18°C (64°F–65°F)
19	19°C (66°F–67°F)
20	20°C (68°F–69°F)
21	21°C (70°F–71°F)
22	22°C (72°F)
23	23°C (73°F–74°F)
24	24°C or more (75°F or more)
25	Do not have control over the dwelling's temperature
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

In 2003, how many programmable thermostats did you have in your dwelling?

00 : 13	Thermostats – number in dwelling
96	Valid skip
97	Don't know
98	Refusal

Did you program the thermostat / any of the thermostats?

1	Yes
2	No
6	Valid skip
9	Not stated

How many programmable thermostats were installed in 2003?

00 : 13	Thermostats – number installed in 2003
96	Valid skip
99	Not stated

Section: AC – Air Conditioning

In 2003, did you have central air conditioning?

1	Yes
2	No
7	Don't know

How old is your central air conditioner?

01 : 40	Age – central air conditioner (years)
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Would you say it is...?

01	3 years old or less
02	4 to 5 years old
03	6 to 10 years old
04	11 to 15 years old
05	16 to 20 years old
06	21 to 25 years old
07	26 years old or more
08	Unsure; was there when moved in
96	Valid skip
97	Don't know
99	Not stated

Is your central air conditioner an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

In an average week during the cooling season, how many hours did you use your central air conditioner (AC)?

000 : 168	Central AC – hours per week (cooling season)
996	Valid skip
997	Don't know
998	Refusal
999	Not stated

In 2003, how many window/room air conditioners did you use?

00 : 05	AC window or room – number used
97	Don't know

Was your (most frequently used) window/room air conditioner a...?

1	Louvred unit
2	Non-louvred unit
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

What was the cooling capacity of your (most frequently used) window/room air conditioner in Btus?

05000 : 20000	AC window or room – cooling capacity (Btu)
99996	Valid skip
99997	Don't know
99998	Refusal
99999	Not stated

How old is the (most frequently used) window/room air conditioner?

01 : 35	Age – window or room AC (years)
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Would you say it is...?

01	3 years old or less
02	4 to 5 years old
03	6 to 10 years old
04	11 to 15 years old
05	16 to 20 years old
06	21 to 25 years old
07	26 years old or more
08	Unsure; was there when moved in
96	Valid skip
97	Don't know
99	Not stated

Is your (most frequently used) window/room air conditioner an ENERGY STAR® qualified product?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

In an average week during the cooling season, how many hours did you turn on your (most frequently used) window/room air conditioner?

000 : 168	Window/room AC – hours per week (cooling season)
996	Valid skip
997	Don't know
999	Not stated

In 2003, did you have a central ventilation system, also known as an air exchanger, which provided fresh air for the entire dwelling?

1	Yes
2	No
7	Don't know

Did your air exchanger have a heat recovery system (heat exchanger)?

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

When is the air exchanger used?
. . . All year
. . . Heating season
. . . Cooling season
. . . Occasionally
. . . Never
. . . Other – Specify

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Section: CEF – Ceiling Fans

In 2003, how many ceiling fans did you use?

00 : 10	Ceiling fans – number used
97	Don't know

In an average week during the heating season, how many hours did you use your (most frequently used) ceiling fan?

000 : 168	Ceiling fan – hours per week (heating season)
996	Valid skip
997	Don't know
999	Not stated

During an average week during the cooling season, how many hours did you use your (most frequently used) ceiling fan?

000 : 168	Ceiling fan – hours per week (cooling season)
996	Valid skip
997	Don't know
999	Not stated

Section: DFS – Dwelling Features

In what year was this dwelling originally built?

1900 : 2003	Year of construction of dwelling
9997	Don't know
9998	Refusal

Would you say it was built...?

01	Before 1946
02	Between 1946 and 1960
03	Between 1961 and 1977
04	Between 1978 and 1983
05	Between 1984 and 1995
06	Between 1996 and 2000
07	In 2001 or later
96	Valid skip
97	Don't know
99	Not stated

Excluding the basement, how many storeys does your dwelling have?

01	One storey
02	One and one-half storeys
03	Two storeys
04	Two and one-half storeys
05	Three storeys
06	Split level
07	Other – Specify
96	Valid skip

How many storeys does your building have? Include storeys below ground and penthouses; exclude storeys used only as indoor parking.

01 : 07	Number of storeys building has
96	Valid skip
97	Don't know

How many apartments does your building have?

002 : 200	Number of apartments building has
996	Valid skip
997	Don't know
998	Refusal

On which floor is your apartment located?

0	Basement
1	First floor
2	Second floor
3	Third floor
4	Fourth floor
6	Valid skip

Is there indoor parking in your building?

1	Yes
2	No
6	Valid skip

How many levels of indoor parking are there in your building?

00.5 : 06.0	Number of levels of indoor parking
99.6	Valid skip
99.7	Don't know

Is the indoor parking heated?

1	Yes
2	No
6	Valid skip
7	Don't know

Section: DFN – Dwelling Foundation

Most houses are built on basements, crawl spaces, concrete slabs (slab on grade), or some combination of these. What is your house built over? Is it a...?
. . . Basement
. . . Crawl space
. . . Concrete slab
. . . Pillars
. . . Other – Specify
. . . No foundation

1	Yes
2	No
6	Valid skip

During the heating season, is your basement / crawl space usually heated?

1	Yes
2	No
6	Valid skip
7	Don't know

How many of your basement / crawl space (outside) walls are insulated on the inside?

0	0
1	1
2	2
3	3
4	4
5	Difficult to answer because shape of house is irregular
6	Valid skip
7	Don't know
8	Refusal

What percentage of your basement / crawl space (outside) walls are insulated on the inside?

000 : 100	Percentage of walls that are insulated
996	Valid skip
997	Don't know
998	Refusal
999	Not stated

Section: DG – Dwelling Garage

Does your dwelling have a garage?

1 Yes
2 No
6 Valid skip

Is your garage attached to the dwelling?

1 Yes
2 No
6 Valid skip

Is your garage insulated?

1 Yes
2 No
6 Valid skip
7 Don't know

During the heating season, is your garage usually heated?

1 Yes
2 No
6 Valid skip

What type of garage does your dwelling have? Is it a...?

1 One-car garage
2 Two-car garage
3 Three-or-more-car garage
6 Valid skip
7 Don't know

Section: SOD – Size of Dwelling

What is the heated area of your basement in square feet/metres?

00015 : 20000
Basement – heated area
99996 Valid skip
99997 Don't know
99998 Refusal
99999 Not stated

Would you say it is...?

01 55 square metres or less (600 square feet or less)
02 56 to 95 square metres (601 to 1000 square feet)
03 96 to 140 square metres (1001 to 1500 square feet)
04 141 to 185 square metres (1501 to 2000 square feet)
05 186 to 230 square metres (2001 to 2500 square feet)
06 231 or more square metres (2501 or more square feet)
96 Valid skip
97 Don't know
99 Not stated

What is the inside measurement of the length and width of your basement in feet/metres?

0015 : 0048 Basement – inside length and width
9996 Valid skip
9997 Don't know
9999 Not stated

Excluding the basement and/or garage, what is the heated area of your dwelling in square feet/metres?

00015 : 54450
Dwelling – heated area
99997 Don't know
99998 Refusal
99999 Not stated

Would you say it is...?

01 55 square metres or less (600 square feet or less)
02 56 to 95 square metres (601 to 1000 square feet)
03 96 to 140 square metres (1001 to 1500 square feet)
04 141 to 185 square metres (1501 to 2000 square feet)
05 186 to 230 square metres (2001 to 2500 square feet)
06 231 or more square metres (2501 or more square feet)
96 Valid skip
97 Don't know
99 Not stated

What is the inside measurement of the length and width of your dwelling in feet/metres?

0007 : 0068 Dwelling – inside length and width
9996 Valid skip
9997 Don't know
9999 Not stated

Section: SOG – Size of Garage

What is the size of the heated area of your indoor garage in square feet/metres?

000035 : 010000
Indoor garage – heated area
999996 Valid skip
999997 Don't know
999999 Not stated

Would you say it is...?

01 55 square metres or less (600 square feet or less)
02 56 to 95 square metres (601 to 1000 square feet)
03 96 to 140 square metres (1001 to 1500 square feet)
04 141 to 185 square metres (1501 to 2000 square feet)
05 186 to 230 square metres (2001 to 2500 square feet)
06 231 or more square metres (2501 or more square feet)
96 Valid skip
97 Don't know
99 Not stated

What is the inside measurement of the length and width of your indoor garage in feet/metres?

00004 : 20000
Indoor garage – inside length and width
99996 Valid skip
99997 Don't know
99999 Not stated

Section: SBD – Size of Building

Excluding the indoor parking, what is the heated area of your building in square feet/metres?

000030 : 042000
Building – heated area
999996 Valid skip
999997 Don't know
999998 Refusal
999999 Not stated

Would you say it is...?

01 165 square metres or less (1800 square feet or less)
02 166 to 285 square metres (1801 to 3000 square feet)
03 286 to 420 square metres (3001 to 4500 square feet)
04 421 to 555 square metres (4501 to 6000 square feet)
05 556 to 690 square metres (6001 to 7500 square feet)
06 691 or more square metres (7501 or more square feet)

96	Valid skip
97	Don't know
99	Not stated

What is the inside measurement of the length and width of your building in feet/metres?

00026 : 00150	Building – inside length and width
99996	Valid skip
99997	Don't know
99999	Not stated

Section: AC – Attic and Crawl Space

Does your dwelling have an attic or a crawl space (a space between the roof and the top floor of your dwelling)?

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal

Is your attic or crawl space insulated?

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

Section: WIN – Windows

In 2003, how many windows were replaced or added?

000 : 025	Number of windows replaced/added
996	Valid skip

What type(s) of window(s) was/were installed?
. . . Low-E coating gas-filled double pane
. . . Gas-filled double pane
. . . Standard double pane
. . . Low-E coating gas-filled triple pane
. . . Gas-filled triple pane
. . . Standard triple pane
. . . Other – Specify

1	Yes
2	No
6	Valid skip
7	Don't know

Out of the number of replaced or added windows, how many of them are low-E coating gas-filled double pane?

001 : 002	Number of low-E coating gas-filled double pane
996	Valid skip
999	Not stated

What type(s) of window(s) was/were replaced by the low-E coating gas-filled double pane?
. . . Single pane with storm windows
. . . Single pane without storm windows
. . . Double pane
. . . Triple pane
. . . Not a replacement – additional window(s)
. . . Other – Specify

1	Yes
2	No
6	Valid skip
9	Not stated

Of the remaining number of replaced or added windows, how many of them are gas-filled double pane?

001 : 002	Number of gas-filled double pane
996	Valid skip
999	Not stated

What type(s) of window(s) was/were replaced by the gas-filled double pane?
. . . Single pane with storm windows
. . . Single pane without storm windows
. . . Double pane
. . .Triple pane
. . . Not a replacement – additional window(s)
. . . Other – Specify

1	Yes
2	No
6	Valid skip
9	Not stated

Of the remaining number of replaced or added windows, how many are standard double pane?

001 : 003	Number of standard double pane
996	Valid skip
999	Not stated

What type(s) of window(s) was/were replaced by the standard double pane?
. . . Single pane with storm windows
. . . Single pane without storm windows
. . . Double pane
. . . Triple pane
. . . Not a replacement – additional window(s)
. . . Other – Specify

1	Yes
2	No
6	Valid skip
9	Not stated

Of the remaining number of replaced or added windows, how many are low-E coating gas-filled triple pane?

001 : 025	Number of low-E coating gas-filled triple pane
996	Valid skip
999	Not stated

What type(s) of window(s) was/were replaced by the low-E coating gas-filled triple pane?
. . . Single pane with storm windows
. . . Single pane without storm windows
. . . Double pane
. . . Triple pane
. . . Not a replacement – additional window(s)
. . . Other – Specify

1	Yes
2	No
6	Valid skip
9	Not stated

Of the remaining number of replaced or added windows, how many are gas-filled triple pane?

006 : 006	Number of gas-filled triple pane
996	Valid skip
999	Not stated

What type(s) of window(s) was/were replaced by the gas-filled triple pane?
. . . Single pane with storm windows
. . . Single pane without storm windows
. . . Double pane
. . . Triple pane
. . . Not a replacement – additional window(s)
. . . Other – Specify

1	Yes
2	No
6	Valid skip
9	Not stated

Of the remaining number of replaced or added windows, how many are standard triple pane?

002 : 006	Number of standard triple pane
996	Valid skip
997	Don’t know
999	Not stated

What type(s) of window(s) was/were replaced by the standard triple pane?
. . . Single pane with storm windows
. . . Single pane without storm windows
. . . Double pane
. . . Triple pane
. . . Not a replacement – additional window(s)
. . . Other – Specify

1	Yes
2	No
6	Valid skip
9	Not stated

What type(s) of window(s) was/were replaced?
. . . Single pane with storm windows
. . . Single pane without storm windows
. . . Double pane
. . . Triple pane
. . . Not a replacement – additional window(s)
. . . Other – Specify

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

In 2003 (not counting the newly installed windows), were any improvements made to the caulking or weatherstripping of your windows?

1	Yes
2	No
7	Don't know

On how many windows was the caulking or weatherstripping improved?

01 : 25	Number of windows improved
96	Valid skip
97	Don't know
99	Not stated

During the heating season, do you put up plastic film on your windows?

1	Yes
2	No
7	Don't know

Have you noticed any condensation on the inside surfaces of your windows?

1	Yes, on most of the windows
2	Yes, on some of the windows
3	No

Have you noticed any air leaks or drafts around your windows?

1	Yes
2	No
7	Don't know

Section: IMP – Improvements

In 2003, did you make any of the following improvements to your dwelling that reduced energy consumption?
. . . Roof structure or surface
. . . Exterior wall siding
. . . Insulation of the roof or the attic
. . . Insulation of the basement or crawl space walls
. . . Insulation of any exterior walls (excluding the basement)
. . . Foundation
. . . Heating equipment
. . . Ventilation or air-conditioning equipment
. . . None of the above

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

In 2004, do you plan to make any of the following improvements to your dwelling that will reduce energy consumption?
. . . Roof structure or surface
. . . Exterior wall siding
. . . Insulation of the roof or the attic
. . . Insulation of the basement or crawl space walls
. . . Insulation of any exterior walls (excluding the basement)
. . . Foundation
. . . Heating equipment
. . . Ventilation or air-conditioning equipment
. . . None of the above

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

What is the main reason you have not made any improvements or plan not to make any improvements in the future?

01	No improvements necessary
02	Improvements too costly
03	Not aware of government financial aid or assistance
04	No government financial aid or assistance
05	Do not have time
06	Other – Specify
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Section: LIT – Lighting

How many halogen light bulbs do you use? Please include halogen spotlights.

000 : 100	Number of halogen light bulbs used
997	Don't know

How many compact fluorescent lights do you use?

000 : 100	Number of compact fluorescent lights used
997	Don't know

Excluding the compact fluorescent lights, how many fluorescent lights do you use? For example, fluorescent tubes.

000 : 076	Number of fluorescent lights used
997	Don't know

How many security lights in motion detector fixtures do you use outdoors?

00 : 13	Number of security lights used
97	Don't know
98	Refusal

How many ordinary (incandescent) light bulbs do you use in your dwelling? (Please include ordinary light bulbs in your basement.)

000 : 100	Number of ordinary light bulbs used
997	Don't know

On an average day, do you turn on any ordinary (incandescent) light bulbs for more than three hours?

1	Yes
2	No
7	Don't know

Are any of the ordinary (incandescent) light bulbs that are turned on for more than three hours in a standard socket?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

How many of the ordinary (incandescent) light bulbs that are in standard sockets and that are turned on for more than three hours do you have?

01 : 25	Number of ordinary lights on three hours or more
96	Valid skip
97	Don't know
99	Not stated

What is the wattage of (this (the most used) ordinary (incandescent) light bulb in a standard socket, that is (turned) on for more than three hours)?

0025 : 0300	Wattage of light on over three hours
9996	Valid skip
9997	Don't know
9999	Not stated

On an average day, for how many hours do you have (the (most used) ordinary (incandescent) light bulb in a standard socket turned on)?

03 : 24	Hours light on per day
96	Valid skip
97	Don't know
99	Not stated

What is the wattage of the second most used of these light bulbs?

0025 : 0240	Wattage of second light
9996	Valid skip
9997	Don't know
9999	Not stated

On an average day, for how many hours is the second most often used of these light bulbs turned on?

03 : 24	Hours second light on per day
96	Valid skip
97	Don't know
99	Not stated

Section: PNW – Pools and Water Devices

Do you use a hot water tank?

1	Yes
2	No
7	Don't know

Is it located in the dwelling?

1	Yes
2	No
6	Valid skip
9	Not stated

What source of energy is used to heat the running water in your dwelling?

01	Electricity
02	Oil
03	Natural gas
04	Propane
05	Solar panel
06	Other source
07	No hot running water
96	Valid skip
97	Don't know
98	Refusal

How old is your hot water tank?

01 : 50	Age – hot water tank (years)
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Would you say it is...?

01	5 years old or less
02	6 to 10 years old
03	11 to 15 years old
04	16 to 20 years old
05	21 to 25 years old
06	26 years old or more
07	Unsure, was there when moved in
96	Valid skip
97	Don't know
99	Not stated

Was your previous hot water tank still working when you replaced it with this one?

1	Yes
2	No
3	This is the original/first hot water tank
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

Approximately how old was your previous hot water tank when you replaced it with this one?

01	5 years old or less
02	6 to 10 years old
03	11 to 15 years old
04	16 to 20 years old
05	21 to 25 years old
06	26 years old or more
96	Valid skip
97	Don't know
98	Refusal
99	Not stated

Is there add-on insulation around the outside of your hot water tank (an insulation blanket)?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Was the add-on insulation around the tank added in 2003?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Is there add-on insulation around the hot water pipes?

1	Yes
2	No
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

Was the add-on insulation around the pipes added in 2003?

1	Yes
2	No
6	Valid skip
7	Don't know
9	Not stated

Do you use a water-saving shower head?

1	Yes
2	No
7	Don't know
8	Refusal

Do you use tap attachments, such as screens or aerators, that reduce the flow of water?

1	Yes
2	No
7	Don't know

Do you have a swimming pool with a filter, solely for the use of your dwelling?

1	Yes
2	No
6	Valid skip

Is there a swimming pool with a filter for the use of the occupants in your building?

1	Yes
2	No
6	Valid skip
7	Don't know

Do you use a pool heater?

1	Yes
2	No
6	Valid skip

What main source of energy does your pool heater use?

01	Natural gas
02	Electricity
03	Oil
04	Propane
05	Solar panel
06	Other source
96	Valid skip

Do you use a programmable timer control on the pool's filter?

1	Yes
2	No
6	Valid skip
7	Don't know

Section: EU – Energy Use

In 2003, on an average weekday, was there someone at home all day? For example, someone taking care of children, someone retired, someone working at home, etc.

1	Yes
2	No
7	Don't know
8	Refusal

In 2003, for how many complete weeks was there no one at your dwelling? For example, on vacation, away on business travel, etc.

00 : 52	Number of weeks no one at dwelling
97	Don't know
98	Refusal

Household income is an important factor in the analysis of information. For the year 2003, what is your best estimate of the total income, before taxes and deductions, of all household members from all sources?

0000000	
9999997	Don't know
9999998	Refusal

Can you estimate in which of the following groups your household income falls? Was the total household income less than $20,000 or $20,000 or more?

1	Less than $20,000
2	$20,000 or more
6	Valid skip
7	Don't know
8	Refusal

Was the total household income from all sources less than $40,000 or $40,000 or more?

1	Less than $40,000
2	$40,000 or more
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

Was the total household income from all sources...?

1	Less than $60,000
2	$60,000 to less than $80,000
3	$80,000 or more
6	Valid skip
7	Don't know
8	Refusal
9	Not stated

So far, you have indicated that your household uses the following source(s) of energy:

electricity / natural gas / heating oil / propane / wood
Does your household use any other energy sources?

1	Yes
2	No
7	Don't know

Which one(s)...?
. . . Solar panel
. . . Wind power
. . . Other – Specify

1	Yes
2	No
6	Valid skip
9	Not stated

You have reported that no one in your dwelling was responsible for paying the bills for the following source(s) of energy:

electricity / natural gas / heating oil / propane
Is this correct?

1	Yes
2	No
6	Valid skip

In 2003, did your household pay bills for...?
. . . Electricity
. . . Natural gas
. . . Heating oil
. . . Propane
. . . None of the above

1	Yes
2	No
6	Valid skip

In 2003, were all of your dwelling's energy bills strictly for the energy consumed by your household? I mean that other charges for operating a farm, a business such as hairdresser, childcare, machine shop or for another dwellings such as apartments, etc. were not included in your energy bills?

1	Yes
2	No
6	Valid skip
7	Don't know

In 2003, approximately what proportion of the electricity consumption on your bills was strictly for your household's use?

000 : 100	Portion of electricity household use
996	Valid skip
997	Don't know
998	Refusal

In 2003, approximately what proportion of the natural gas consumption on your bills was strictly for your household's use?

000 : 100	Portion of natural gas household use
996	Valid skip
997	Don't know
998	Refusal

In 2003, approximately what proportion of the heating oil consumption on your bills was strictly for your household's use?

000 : 100	Portion of heating oil household use
996	Valid skip

In 2003, approximately what proportion of the propane gas consumption on your bills was strictly for your household's use?

050 : 100	Portion of propane gas household use
996	Valid skip

Section: CES – Contact Energy Suppliers

Do you agree to let Statistics Canada contact your
. . . Electricity supplier(s)?
. . . Natural gas supplier(s)?
. . . Heating oil supplier(s)?
. . . Propane gas supplier(s)?

1	Yes
2	No
6	Valid skip
7	Don't know

Can you provide me with your electricity, natural gas, heating oil and/or propane gas billing information for the period that covers all or part of January 2003 to December 2003 so that I can enter the data on my computer?

1	Yes
2	No
6	Valid skip
8	Refusal

INTERVIEWER: Please ask the ACCOUNT HOLDER to provide you with a copy of an electricity, natural gas, heating oil and/or propane gas bill or contract so that you can transcribe the information onto the Consent Form.

Please note that the ACCOUNT HOLDER may have to provide the information from a computer if e-billing is used.

Once you have transcribed all the information, ask the ACCOUNT HOLDER to verify the information and sign the consent form. Ensure that all mandatory fields are completed. Indicate the consent form status.

1	Consent form has been signed
2	Consent form will be mailed back
6	Valid skip
8	Refusal
9	Not stated

Section: PCL – Permission to Contact Landlord

Is your landlord or property management responsible for paying the
. . . Electricity bills?
. . . Natural gas bills?
. . . Oil bills?
. . . Propane gas bills?

1	Yes
2	No
6	Valid skip

In order to contact the landlord / property management, we need your permission. We will also need the landlord / property management's name, address and telephone number. The information collected from the landlord / property management will be used for research purposes only and will be kept confidential.

Do you agree to let Statistics Canada contact your landlord / property management?

1	Yes
2	No
6	Valid skip

Section: Exit Variables

Permission to share respondent's (Occupant) information. Based on following question:

Do you agree to allow Statistics Canada to share your information with NRCan?

1	Yes
2	No

Permission to share respondent's (Landlord) information. Based on following question:

Do you agree to allow Statistics Canada to share your information with NRCan?

1	Yes
2	No
6	Valid skip
9	Not stated

Natural Resources Canada's Office of Energy Efficiency

Leading Canadians to Energy Efficiency at Home, at Work and on the Road

Attachment 71.1

Final Report

Impact of Terasen Gas / Energy Star Heating System Upgrade (2003) Program

Prepared for: Terasen Gas

Prepared by:

Habart & Associates Consulting Inc.

August 2004

Table of Contents

i. Executive Summary

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. This incentive was combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers. For the 2003 program, the furnace or boiler had to be purchased from September 1, 2003 to December 15, 2003. Participants received a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada. The program was expanded from the previous year to include a financing option and an additional $150 rebate for furnaces including a variable speed blower motor. During this time period 2,915 people participated in the program, up from 2,785 in the 2002 program.

The objective of this study was to provide an impact, process and market evaluation of the 2003 program and build on the evaluation experience of the previous two year's programs. Following a review of the 2002 program evaluation, fourteen evaluation areas emerged:

- Determine customer and trade ally satisfaction with the program.
- Assess impact of marketing / advertising of program.
- Assess effectiveness of financing vs. rebates as incentives.
- Determine installed prices of mid and high efficiency furnaces (HEF).
- Assess program impact on sales of high efficiency furnaces.
- Assess program impact on sales of variable speed blower motors (VSM).
- Determine the usage of furnace blowers before and after the furnace replacement.
- Assess change in the use of secondary heating after installation of HEF furnace.
- Examine determinants of HEF program participation.
- Examine determinants of VSM incentive participation.
- Provide discrete choice based estimates of energy savings.
- Provide discrete choice based estimates of carbon dioxide reductions.
- Determine status of market transformation in the BC furnace market.
- Determine pre/post change in weather adjusted natural gas consumption.

Given the wide scope of these evaluation areas, a number of data sources and methods were used in this study. Telephone interviews were conducted with approximately 100 participants and 100 non-participants[1] as well as 40 trade allies who had participated in the program. The survey data was combined with information from Terasen Gas' program data bases to provide answers to the fourteen evaluation areas noted above. In this report, the impact numbers were developed based on engineering estimates. Once sufficient billing data is available, the impact estimates will be re-developed based on the billing data.

[1] It should be noted that, for the purpose of this study, non-participants were defined as people who purchased a furnace, but who did not participate in the Terasen Gas program as this approach was felt to provide more valuable information on the state of the furnace market than using a general population recruit.

This analysis will be done in the fall of 2005.

The conclusions of the study are as follows:

Conclusion 1: customer and trade ally satisfaction with the program:

Maintaining high levels of customer satisfaction is a key concern of program management and staff. Satisfaction with a variety of program components was rated on a five-point scale where one is not at all satisfied and five is very satisfied. Participants reported satisfaction levels averaging 3.8 or more for application procedures, information on the rebate, information abut efficient furnaces and types of furnaces eligible for the rebate. Lower levels of satisfaction were expressed for the time period of the program and the amount of the rebate, but these are 3.7 and still quite positive. Trade Allies reported satisfaction of 3.8 or higher for the amount of the rebate, types of furnaces eligible for a rebate, information on the rebate and application processing. The program continues to achieve high levels of customer and trade ally satisfaction.

Conclusion 2: impact of marketing / advertising of program:

Advertising and promotional activities are a key means of increasing program awareness and participation. For participants and non-participants, the main sources of awareness are the insert in the Terasen Gas bill, the heating contractor and word of mouth. However, with the exception of bill inserts, these sources of awareness are all quoted at lower levels by non-participants. Compared with the 2002 evaluation, awareness of the program by non-participants has declined from about 41% to 31%. At the same time it appears that the demographics of non-participants has also changed. In 2003 over 68% of the non-participants were age 55 and over whereas in 2002 only 50% fell into this category. This shift in demographics may indicate a need for different strategies to reach the older age groups. A second possible cause for the decline in awareness is that in 2002, the Furnace Tune-up program had 45,000 participants which may have generated broader awareness of all Terasen programs.

Conclusion 3: effectiveness of financing vs rebates as incentives:

The 2003 program included a finance option for the first time. Analysis of program records indicates that only 211 of the 2,915 participants, or about 7%, took advantage of the option. However 57% of these people, or 120 participants indicated that, without the financing option, they would not have purchased a new furnace at this time. Therefore it can be concluded that the finance option increased the program sales by about 4%, or about the total increase in sales between 2002 and 2003.

Conclusion 4: installed prices of mid and high efficiency furnaces (HEF):

One of the indicators of market transformation is the reduction of prices, or at least of price premiums, for energy efficient products to the consumer. While there is some indication of a general price rise for all furnaces between 2002 and 2003, there also appears to have been a decrease in the incremental installed price of a high efficiency furnace relative to a mid efficiency furnace. The incremental price has dropped from $877 to $608, or about 30%. This is the equivalent of a reduction in payback period from 5.6 years in 2002 to 3.9 years in 2003.

Conclusion 5: program impact on sales of high efficiency furnaces:

Three approaches to determining program attribution were considered: (1) responses to customer survey questions; (2) responses to trade ally survey questions, and (3) the Discrete Choice approach. These different approaches provided an attribution of 57% from the Customer survey, 76% from the Trade Ally survey and 72.3% from the Discrete Choice analysis. The Discrete Choice estimate was used as this approach is typically less biased and better reflects the impact of the overall program rather than just the incentive component.

Conclusion 6: program impact on sales of variable speed blower motors (VSM):

Impact of the program on sales of VSMs is less clear than for high efficiency furnaces. Both Customers and Trade Allies were asked about the importance of the program in their choice of furnace with VSM. The Customers' survey indicated an attribution rate of 61% to the program while the Trade Allies indicated a lower rate of 50%. However a comparison of adoption rates between participants and non-participants showed an increase in sales to participants of only 41%.

Conclusion 7: usage of furnace blowers before and after the furnace replacement:

Customers and Trade Allies were queried about the use of their furnace blowers before and after the installation of the new furnace. Analysis of the Customer data shows that people who were making use of the furnaces to provide various levels of ventilation (ie: not just when the system is providing heating or cooling) were more likely to buy a furnace with a VSM. Data on blower usage after the furnace was installed shows that usage of the blower only when providing heating or cooling declined from 73% to 64% with more intensive uses of the blower increasing by a similar amount. However most of this increased blower usage is going to furnaces with VSMs. For example, when comparing blower usage before the furnace installation with just those people who installed VSMs, the usage when only providing heating or cooling declines from 73% to 55%. The Trade Ally data confirms these trends, but shows an even stronger shift to continuous ventilation.

Conclusion 8: change in the use of secondary heating after installation of HEF furnace:

The Customer survey determined that 42% of participants decreased their use of secondary space heating after installing the new furnace while only 5% increased their usage. If the space heating fuel is other than natural gas, a reduction in secondary heating will increase the load on the furnace. However if the secondary heating fuel is natural gas, and the secondary heating source is less efficient that the furnace, a reduction in secondary heating will increase the natural gas savings as the load is picked up by the more efficient furnace. The potential impact from the reduction in secondary heating after the installation of the high efficiency furnace appears small, in the order of -0.7 GJ per year. Given the significant assumptions required for this analysis, it was concluded not to include any impact from secondary heating in the program impacts.

Conclusion 9: determinants of HEF program participation:

The discrete choice analysis for the overall furnace program found that the primary determinants of program participation were: consumption of natural gas; importance of energy efficiency and importance of costs. This is also reflected by survey questions on the importance of various influencers on heating system choice (measured on a 5 point scale) which included: energy efficiency (4.5); comfort (4.4); and operating cost (4.3).

Conclusion 10: determinants of VSM incentive participation:

The primary drivers for participation in the VSM incentive component of the program were: energy efficiency (49%); contractor recommendation (23%); quieter operation (10%) and wanted continuous ventilation (10%).

Conclusion 11: discrete choice based estimates of energy savings:

To estimate energy savings, unit savings are multiplied by the number of gross participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio. Estimated net savings are 37.4TJ for the first 5.4 years and 26.6TJ for subsequent years. Estimated peak day savings are the weighted peak day heating load share for January multiplied by net savings. Estimated peak day savings are 0.20TJ for the first 5.4 years and then 0.15TJ for subsequent years.

Conclusion 12: discrete choice based estimates of carbon dioxide reductions

Using an emissions factor of 50 tonnes of carbon dioxide per terajoule yields an emissions reduction or carbon dioxide savings of 1.87 kilotonnes of carbon dioxide for the first 5.4 years of the program and 1.33 kilotonnes of carbon dioxide for subsequent years of the program.

Conclusion 13: status of market transformation in the BC furnace market:

Two indicators of market transformation are considered in this evaluation, changes in market share of high efficiency furnaces over time and changes in customer payback, with increasing market share and improving payback being considered as indicators of market transformation.

- The market share of high efficiency furnaces in the retrofit segment has increased from about 38% in 2001 to about 57% in

2003 while the estimate of the overall furnace market served by Trade Allies included in the study has increased from 29% to about 52%.

- Based on typical furnace prices provided by the Trade Allies, it appears that the incremental cost of installing an high efficiency furnace relative to a mid efficiency furnace has dropped between 2002 and 2003, with a reduction in payback period to the customer dropping from 5.6 years to 3.9 years.

These indicators suggest that the program is making substantial progress in transforming the market for furnaces in B.C.

1. Introduction

1.1 Program Overview

Energy conservation programs have two main rationales: environmental and economic.

- The environmental rationale is that reducing energy consumption can reduce harmful emissions implicated in global warming. Canada has joined most of the international community by signing the Kyoto Protocol in December 1997 and committed itself to reducing greenhouse gas emissions by six percent below the levels in 1990 between 2008 and 2012. While the fate of the Kyoto Protocol itself is uncertain there is still a consensus that reducing GHGs is beneficial.
- The economic rationale is that reducing energy consumption and peak demand can reduce costs to both utilities and their customers if the marginal cost of energy conservation is less than the marginal cost of new supply.

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. In 2003, a financing option was added to the previous $ 300 grant. Also, an additional $ 150 incentive was provided for customers who chose furnace models with a variable speed blower motor (VSM). These incentives were combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers.

For the 2003 program, the furnace or boiler had to be purchased from September 1, 2003 to December 15, 2003. Participants received a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada. During this time period 2,915 people participated in the program, up from 2,785 who had participated in the 2002 program. Of the participants, 2704 received the $ 300 grant while 211 chose financing. One thousand, six hundred and twelve (1,612) purchased furnaces with variable speed motors (VSM) for the furnace blower, 1474 in BC Hydro's service area and 138 in Aquila's (now Fortis BC's) service territory. Fifty-one percent of the participants were from the Lower Mainland, while the remainder was from the Interior (including the Columbia area).

Program objectives for the Terasen Gas Heating System Upgrade Program included the following: realize residential energy savings; improve residential customer energy awareness; transform the residential furnace market; and assist residential customers in managing energy costs.

1.2 Outline of the Report

This report provides a process, market and impact evaluation of the Heating System Upgrade Program. Section 1 provides an overview of the Heating System Upgrade Program and of this study. Section 2 discusses the study objectives, approach, evaluation areas and methods used. Section 3 describes the key program elements including program design, program marketing and program delivery. Section 4 presents the results of the consumer survey. Section 5 presents the results of the trade ally survey. Section 6 summarizes the impact results including the effect of the program on furnace sales and market share, furnace prices, energy savings and carbon dioxide emissions. Section 7 provides the conclusions of the study.

2. Objectives and Approach

2.1 Study Objectives and Approach

Governments, regulators and utilities are looking to incentive programs to deliver cost effective energy savings and reduce greenhouse gas emissions. Evaluation of space heating and appliance incentive programs leads to analysis of four key objectives: first, to what extent does the incentive program result in incremental or additional purchases of the efficient measure; second, what impact does the incentive program have on prices for the technology paid in the market; third, how large are the energy savings that can validly be attributed to the program; fourth, what are the program impacts on GHG emissions?

In typical program evaluations, considerable effort is placed on obtaining accurate estimates of gross technology savings, but less attention is given to market effects including price impacts of incentives, determinants of technology adoption, free rider analysis and technology costs. In this study we have provided Terasen Gas with a more useful and credible analysis by collecting valid information on market effects including prices and sales through detailed telephone surveys, and then combining this information with existing program data and engineering algorithms to undertake rigorous analysis of all evaluation areas.

The evaluation design includes a second phase of impact evaluation based on the analysis of billing consumption once the furnaces have been installed for a full heating season. It is anticipated that this work will be undertaken during the summer of 2005.

2.2 Study Areas and Methods

Following the initial team discussions and review of the 2002 program evaluation, fourteen critical study areas emerged for this study:

- Determine customer and trade ally satisfaction with the program.
- Assess impact of marketing / advertising of program.
- Assess effectiveness of financing vs rebates as incentives.
- Determine installed prices of mid and high efficiency furnaces (HEF).
- Assess program impact on sales of high efficiency furnaces.
- Assess program impact on sales of variable speed blower motors (VSM).
- Determine the usage of furnace blowers before and after the furnace replacement.
- Assess change in the use of secondary heating after installation of HEF furnace.
- Examine determinants of HEF program participation.
- Examine determinants of VSM incentive participation.
- Provide discrete choice based estimates of energy savings.
- Provide discrete choice based estimates of carbon dioxide reductions.
- Determine status of market transformation in the BC furnace market.
- Determine pre/post change in weather adjusted natural gas consumption.

Given the wide scope of these study areas, a number of data sources and methods were used in this study. An outline of the evaluation areas, data sources and methods is shown in Exhibit 2.2.1.

This evaluation will be done in two Phases. The first phase includes the market research and analysis required to meet the fourteen objectives noted above, although the substantive work for the last issue will constitute the second phase. The evaluation included program participants from the 2003 programs and non-participants who purchased a furnace in 2003 or 2004, but did not participate in the program. The survey work was done between May 25 and June 6 of 2003. The completion rate for participants was 36%, while the completion rate for non-participants (defined as people who had purchased a furnace in 2002 or 2003, but who had not participated in the Terasen program) was 2.8%. The lower completion rate for non-participants reflects the absence of contact information for these households which meant that a random telephone survey was required. In each year, about 2.7% of the population purchases a replacement furnace.

Phase 1 includes the data collection and an initial impact analysis based on engineering estimates and the results of a discrete choice analysis. However, this approach does not allow the savings estimates to be based on actual consumption, or billing history, as customers have not had the new heating equipment installed for a full heating season. Once the billing history is available, we will complete Phase 2 and re-calculate the energy impact for the program based on the actual billing history. For the 2003 participants, the billing history is expected to be available by summer 2005.

Exhibit 2.2.1. Evaluation Areas, Data Sources and Methods

Evaluation Issue	Data Sources	Methods
Phase 1.		
1. Determine customer / trade ally preferences for future programs.	Customer survey Trade ally survey	Cross tabulations
2. Assess impact of marketing / advertising of program.	Customer survey Trade ally survey	Cross tabulations
3. Assess effectiveness of financing vs. rebates as incentive.	Customer survey Trade ally survey	Cross tabulations
4. Determine installed prices of mid and high efficiency furnaces	Customer survey	Pre/post comparisons
5. Assess program impact on sales of high efficiency furnace.	Customer survey	Cross tabulations
6. Assess program impact on sales of variable speed blower motors.	Customer survey	Cross tabulations
7. Determine usage of furnace blowers before and after furnace replacement.	Customer survey Trade ally survey	Cross tabulations
8. Assess installation of HEF furnace on the use of secondary heating.	Customer survey	Cross tabulations
9. Examine determinants of HEF furnace program participation.	Customer survey	Discrete choice modelling
10. Examine determinants of VSM motor rebate participation.	Customer survey	Discrete choice modelling Cross tabulations
11. Provide discrete choice based estimates of program impact to determine energy savings	Program records Previous research Customer survey	Engineering algorithms
12. Provide discrete choice based estimates of program impact to determine carbon dioxide reductions.	Program records Previous research Customer survey	Engineering algorithms
13. Determine status of furnace market transformation in B.C.	Customer survey Trade ally survey	Cross tabulations
Phase 2		
14. Determine pre/post change in weather adjusted natural gas consumption	Billing records Weather files	Weather adjusted billing analysis
14a. Revise discrete choice based estimates of program impact to determine energy savings	Billing Analysis Previous research	Engineering algorithms
14b. Revise discrete choice based estimates of program impact to determine carbon dioxide reductions.	Billing Analysis Previous research	Engineering algorithms

The customer survey collected information on the following:

- Customer awareness of the program.
- Customer satisfaction with the program and its components.

- Customer incentive preference
- Customer demographic characteristics.
- Furnace blower motor characteristics, preferences and usage.
- Furnace characteristics including age, capacity and price.
- Housing characteristics including size and fuel types.
- Program barriers and opportunities.
- Program design issues.

The trade ally survey collected information on the following:

- Trade ally awareness.
- Trade ally satisfaction with the program and its components.
- Trade ally firm characteristics.
- Characteristics of furnaces sold including efficiency level, fan usage and price as well as market characteristics.
- Program barriers and opportunities.
- Program design issues.

It was determined that telephone surveys would be the best way to collect timely information while minimizing the response burden. The surveys were designed to provide as much comparability between survey groups as possible. This maximized the number of issues for which responses could be compared across the groups. The draft survey instrument was pre-tested and modified to improve several questions and the questionnaire flow.

Because of the detailed nature of the research questions, particular care had to be used in the development of sample frames for the three groups: program participants or people who had received a rebate through the program; program non-participants or people who had purchased a new furnace outside the program during 2002 or 2003; and trade allies. The final sample consisted of 100 participants, 100 non-participants, and 40 trade allies.

As the evaluation design includes the use of billing analysis to determine the impact of the program, care was taken to screen potential respondents for acceptable billing histories prior to launching the telephone survey[2]. All participants were screened, and approximately 2,100 of the 2,915 were determined to have valid consumption history for the year prior to the program. In addition, a list of 35,000 potential candidates was developed for use in surveying a comparison group. This large list was required as the comparison group was defined as household that had purchased a furnace outside of the program and the incidence was estimated at 2.7% of the population. This list was also screened against the participants list to reduce the probability of surveying a person twice.

The telephone surveys were conducted between May 25 and June 6 of 2003 using a CATI system. Interviewers were fully briefed before the surveys were conducted to ensure that they understood the intent of the overall survey as well

[2] The methodology used for screening the billing history is included as Appendix A.

as each individual question. Up to five calls were made to each potential respondent to minimize response bias. Qualifying questions were asked to ensure that the appropriate individual completed the survey. As the responses were given, they were entered into an electronic database. Responses were then edited and cleaned.

Analysis of energy savings due to the program requires some care, because replacement of an existing, typically standard efficiency furnace with a new furnace (with minimum AFUE of 78% under the regulations of the Energy Efficiency Act) will substantially reduce natural gas consumption, whether or not a high efficiency furnace is installed. Energy savings due to the program will fall into two categories. First, for all customers, direct savings include the impact of moving from a mid efficiency furnace to a high efficiency furnace. Second, for some customers the program induced them to replace their furnace sooner than they otherwise would have. These spillover savings include the savings of moving from a standard efficiency furnace to a mid efficiency furnace for the early replacement period.

The billing analysis conducted for the 2002 Residential Heating System Upgrade Program[3] determined that the efficiency of the average furnace replaced during that year's program was 70.6%. This estimate is used for the 2003 evaluation rather than the 60% estimate used previously. This study also estimated the consumption of the average replaced furnace at 91.5 GJ.

Direct annual energy savings are based on Equation (1).

(1) Energy savings = 91.5 GJ * (0.706/0.78 – 0.706/0.920)*(1 - FR)*(Gross participants)

where 91.5 GJ is the estimated base space heating load for program participants, 0.706 is the assumed AFUE for the old furnace or boiler, 0.920 is the typical AFUE for high efficiency natural gas furnaces, 0.780 is the minimum AFUE under the regulations of the Energy Efficiency Act, (1 – FR) is one minus the free rider rate estimated from residential customer survey data, and gross participants is the number of furnaces receiving rebates from program data in 2003. These savings pertain to the expected life of the furnace.

In addition to the direct annual energy savings noted above, it was determined through the surveys that the program induced people to replace furnaces earlier than they otherwise would have. This is classed as spillover savings and the estimation is based on Equation (2).

(2) Energy savings = 91.5 GJ * (0.706/0.706 – 0.706/0.780)*(Gross early participants)* (Average years replaced early)

where 91.5 GJ is the estimated base space heating load for program participants,

[3] "Billing Analysis – 2002 Residential Heating System Upgrade Program Evaluation", Terasen Gas, July 28, 2004

0.706 is the assumed AFUE for the old furnace or boiler, 0.780 is the minimum AFUE under the regulations of the Energy Efficiency Act, gross early participants is the attribution rate (or the share of furnaces replaced prematurely due to the program from customer survey data) times the number of furnaces rebated from program data in 2002. These savings pertain to the number of years the furnace would have been used before replacement.

Peak savings are based on Equation (3).

(3) Peak savings = (January's monthly share of annual heating degree days)*(1/31 days)*Energy savings.

3. Program Description

3.1 Program Design and Implementation

The original purposes of the Heating System Upgrade Program was to encourage home owners to consider energy efficiency when they were making furnace replacement decisions and ultimately to reduce peak natural gas demand, delay the need for incremental system investments, and reduce greenhouse gas emissions due to the residential sector. During program design, research was undertaken to understand residential customer needs and the advantages and weaknesses of alternative program designs.

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. This incentive was combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers. For the 2003 program, the furnace or boiler had to be purchased from September 1, 2003 to December 15, 2003. Participants had the choice of receiving a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada or interest free financing from Homeworks. In addition, participants who chose a furnace with a VSM could also receive a further $ 150 incentive from BC Hydro or Aquila towards the costs of the furnace. Details of the manufacturers' offers vary by manufacturer as shown below in Exhibit 3.1.

Exhibit 3.1. Manufacturers' Rebates

Manufacturer / Product	Terasen Gas and NRCan Rebate	Manufacturer Offer
American Standard – Furnace	$300	10-year parts and labour warranty total valued at $530.
Armstrong – Furnace	$300	Programmable thermostat plus electrostatic filter total valued at $200
Bryant - Furnace/Boiler	$300	10-year parts warrantee plus a programmable thermostat valued at $500
Carrier – Furnace	$300	10-year parts warrantee plus a programmable thermostat valued at $500
Frigidaire – Furnace	$300	Programmable thermostat and $100 discount off installation for a value of $ 200
IBC Technologies Inc. – Boiler	$300	Variable speed pump valued at $350.
Keeprite – Furnace	$300	$150 rebate
Kenmore – Furnace	$300	$150 rebate
Lennox – Furnace	$300	10-year parts and labour warranty valued at $600
Luxaire - Furnace	$300	$150 rebate
Super Hot – Boiler	$300	2-year parts and labour and 15-year heat exchanger warrantee valued at $200.
Tempstar – Furnace	$300	$150 rebate
Trane – Furnace	$300	10-year parts and labour extended warranty total valued at $350-$560
Weil-McLain – GV / Ultra Boiler	$300	$150 rebate (GV) or $ 150 plus 5-year parts and labour warrantee (Ultra) valued at $ 450
York – Furnace	$300	10-year parts and labour extended warranty plus programmable thermostat total valued at $600

3.2 Program Marketing

The Heating System Upgrade Program has used a variety of mechanisms to ensure that potential clients are aware of the program. These mechanisms have included:

- Bill inserts and messages.
- Advertising in Homewest magazines.
- Direct mail.
- Terasen Gas web site advertising.
- Promotion at retail outlets (POP).
- The manufacturers' dealer networks.
- Trades and contractors.
- Call center operators.

3.3 Delivery

In order to receive a rebate, the customer had a high efficiency furnace installed, completed a rebate coupon, attached a copy of the invoice, and forwarded the coupon and the invoice to Terasen Gas' billing area (managed by Accenture Business Services for Utilities (ABSU)). If the required criteria were met, the rebate was processed and the customer's information entered into the program data base. If the relevant criteria were not met, a letter was sent to the customer informing them that the rebate was refused and explaining the reason why. If critical information was missing, a letter was sent to the customer with information on what was missing.

The 2003 program had two significant changes from previous year's program. The first change was that a financing plan was offered, and the second change was that an additional incentive was provided if the furnace included a high efficiency variable speed fan motor (VSM).

The financing plan provided 0% financing over 24 months, on approved credit, for a personal loan between $ 2,000 and $ 4,000. The financing was in lieu of the $ 300 grant. The program was administered by Homeworks Financing, with funding from Citizens Bank of Canada. Administration of the financing program was handled by Homeworks. Some 211 participants took part in the financing program, of which 109 also received the incentive for the VSM.

The high efficiency variable speed motor incentive provided an additional $ 150 if the furnace included an approved variable speed furnace blower motor. This incentive was provided by BC Hydro, Aquila Networks Canada, and Natural Resources Canada. 1,612 participants, or just over 55%, took advantage of this offer.

3.4 Rationale

The rationale for the Heating System Upgrade Program is based on the premise that by providing customers with information on the advantages of high efficiency furnaces together with a financial incentive, customers will be encouraged to install high efficiency furnaces. This will result in significant energy conservation retrofits and measurable reductions in energy consumption and carbon dioxide emissions. Exhibit 3.1 outlines the rationale for the program and its activities. In summary, for each activity, the main linkages among inputs-outputs-outcomes and impacts are shown. There are strong and plausible linkages for each part of this chain confirming the logic of program design.

Exhibit 3.2. Program Logic Model

	Program design and implementation	Program marketing	Program delivery
Inputs	Assess customer needs and develop a program to meet these needs	Promotional activities including bill inserts, website, direct mail	Processing of applications and dispatch of letters to customers
Outputs	Program designed and implemented	Customer awareness of and interest in program increased	Provision of rebates to qualifying customers
Outcomes	Systems in place and operational	Increased customer intent to participate	Improved installation rate for high efficiency furnaces
Impacts	Reduced residential energy and peak consumption Reduced residential energy bills Reduced greenhouse gas emissions		

4. Customer Survey Results

4.1 Customer Awareness

Awareness of a program is the first step in the chain of actions that may eventually lead to program participation. Awareness of the Heating System Upgrade Program for non-participants is shown in Exhibit 4.1 as 31%. In 2002 the awareness level of the program by non-participants was 41% and awareness appears to have declined between 2002 and 2003.

Exhibit 4.1.1. Awareness of Heating System Upgrade Program

	Non-Participants 2003 (%)
Base	100
Yes	31%
No	67%
DK/NR	2

Understanding the importance of sources of program awareness is critical in evaluating the success of promotional strategies. The sources of overall awareness of the program, for those who indicated their awareness of the program in the previous question, are shown in Exhibit 4.1.2. For participants, the most important sources are: insert in Terasen Gas bill, the heating contractor, and word of mouth. For non-participants, the most important sources are the insert in Terasen Gas bill, and the heating contractor.

Exhibit 4.1.2. Source of Program Awareness

	Total (%)	Participants (%)	Non-participants (%)
Base	131	100	31
Insert in Terasen Gas bill	46	44	52
Heating contractor	15	16	10
Word of mouth	11	13	6
Newspaper or Magazine adv.	9	10	6
Direct mail	4	3	6
Terasen web site	4	4	3
Radio advertisement	2	1	6
Salesman / dealer	2	2	3
Home show	2	3	-
TV advertisement	2	2	-
NRCan web site	1	1	-
Other	2	2	-
DK/NR	4	3	6

4.2 Customer Satisfaction

Customers were asked what they liked and least liked about the promotion. Exhibit 4.2.1 shows the major responses. The response is quite favorable with saving money being the first attraction and energy efficiency as the second. Sixty-seven percent (67%) of the respondents had nothing about the program they least liked. Of the 31% of non-respondents who were aware of the program, energy efficiency and saving money were also the main attraction, but non-respondents did not like the restrictions on the types of furnaces. However 58% of the non-respondents had nothing they liked least about the program.

Exhibit 4.2.1. "What did you like about the program"

	Total (%)	Participants (%)	Non-participants (%)
Base	131	100	31
Saving money / got money back	46	55	16
Saved money / more efficient furnace / needed a new furnace	21	27	-
Energy efficiency / good for environment	13	11	19
Informative / easy to understand	6	6	6
Saved money on gas bill	5	5	3
Financing / ability to pay in installments	3	3	3
Warrantee	2	2	-
Other	5	6	1
Nothing in particular	17	7	48
DK/NR	2	1	6

Exhibit 4.2.2. "What did you least like about the program"

	Total (%)	Participants (%)	Non-participants (%)
Base	131	100	31
Rebates not available for all types of furnaces	6	1	23
Lack of information	5	7	-
Rebate was too low	5	6	3
Amount of paperwork / too complicated	3	3	3
Time limit for promotion	3	2	6
Time it took for money to appear	2	3	-
Rebate should apply to self install	2	-	6
Other	3	4	-
Nothing in particular	67	70	58
DK/NR	4	4	3

Customers were asked to indicate their level of satisfaction with the rebate program components on a five-point scale where one is not at all satisfied and five is very satisfied. Exhibit 4.2.3 shows the reported levels of satisfaction with the standard errors shown in parentheses. Participants reported a satisfaction level of 4.2 on the application procedure, and just under 4.0 for information on the program, and information on efficient furnaces. The lowest satisfaction was reported for the time period and amount of the rebate. These are high and significant levels of satisfaction.

Exhibit 4.2.3. Customer Satisfaction with Program Components (mean on 5-point scale)

	Participants (%)
Base	100
Application procedures	4.2 (0.1)
Information on the rebate program	3.9 (0.1)
Information about efficient furnaces	3.9 (0.1)
Type of furnaces eligible for rebate	3.8 (0.1)
Time period for purchasing rebate eligible furnace	3.7 (0.1)
Amount of the rebate	3.7 (0.1)

Note: Standard error in parentheses.

Twenty-eight percent of program participants reported calling the customer call center with regards to the program. Exhibit 4.2.4 outlines the reasons for the calls, most of which focused on understanding the rebate and / or their eligibility for the rebate.

Exhibit 4.2.4. Purpose of this call

	Participants (%)
Base	28
To understand the rebate	39
To clarify eligibility for incentive	32
To understand finance plan	11
To determine if furnace was eligible	11
General information about program	11
How to apply	7
To determine when rebate would appear	4
DK/NR	14

Customers were asked to indicate their level of satisfaction with the various aspects of their furnace on a five-point scale where one is not at all satisfied and five is very satisfied. Exhibit 4.2.5 shows the reported levels of satisfaction with the standard errors shown in parentheses. Participants reported satisfaction levels averaging 4.0 or more for reliability of the furnace, ease of installation of furnace, gas consumption, and after sales service. Non-participants reported satisfaction levels of 4.0 or more for all elements of the program except for the amount of their natural gas bill, which likely reflects the higher share of mid efficiency furnaces that they have purchased.

Exhibit 4.2.5. Customer Satisfaction with Their Furnace (mean on 5-point scale)

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Reliability of furnace	4.5 (0.1)	4.5 (0.1)	4.6 (0.1)
Ease of installation of furnace	4.4 (0.07)	4.3 (0.11)	4.4 (0.09)
Natural gas consumption	4.1 (0.1)	4.0 (0.1)	4.2 (0.1)
After sales service	4.1 (0.1`)	4.0 (0.1)	4.3 (0.1)
Price of furnace	3.8 (0.1)	3.6 (0.1)	4.1 (0.1)
Amount of natural gas bill	3.8 (0.1)	3.8 (0.1)	3.7 (0.1)

Note: Standard error in parentheses.

Respondents were asked if they had any problems with their new furnace. As Exhibit 4.2.6 shows, the share of respondents reporting problems was about 15%, 21% for participants and about 9% for non-participants. By furnace blower, 18% of those with VSMs had problems while 14% with standard furnace motors experienced difficulties. This difference is quite small, but may indicate that there are still some problems with this relatively new technology.

Exhibit 4.2.6. Had any Problems with Furnace

	Total (%)	Participants (%)	Non-participants (%)	PSC	VSM
Base	200	100	100	74	111
Yes	15	21	9	14	18
No	85	79	91	86	82
DK/NR	-	-	-		

Respondents were then asked about the types of problems experienced. Among those with problems with their furnace, the most common problems were: the furnace had required major repairs; the furnace was too noisy; and furnace had excessive vibration. Exhibit 4.2.7 summarizes the types of problems encountered. Excess noise was the most common complain. A detailed review of the responses indicated that this problem was reported almost three times as often by customers with VSMs. Similarly, excess vibration was also reported more often for furnaces with VSMs. (Note: This may result from a known problem when VSMs are installed in houses where the duct work is too small, which can result in both noise and vibration. If so, this may be addressed through contractor / sales staff training).

Exhibit 4.2.7. Have you experienced any of the following problems with your furnace?

	Total (%)	Partici-pants (%)	Non-partici-pants (%)	PSC (%)	VSM (%)
Base	30	21	9	10	20
Furnace too noisy	37	29	56	20	45
Furnace has required major repairs	13	10	22	10	15
Furnace cycles off and on too frequently	13	10	22	20	10
Furnace has excess vibration	10	10	11	-	15
Leaks / condensation problems	10	14	-	-	15
The fan needed to be replaced	7	10	-	10	15
Furnace produced an uncomfortable draft	7	5	11	20	-
Difficult to maintain the right temperature	3	5	-	-	10
Furnace size is too small	3	-	1	-	-
Other	27	38	-	30	25
DK/NR	7	5	11	10	5

*Note: Multiple Responses – columns will not sum to 100%.

4.3 House Comfort

Information was collected on a variety of issues related to home comfort and secondary heating to better understand why households choose different levels of efficiency, interest in VSM, and to help explain changes in the use of secondary heating following Participants reported a higher level of increased comfort than did non-participants. Similarly, households with VSMs reported a higher level of comfort than those with PSCs[4]. For participants with VSMs, the level of increased comfort was 78% compared with 58% overall for PSCs.

[4] Permanent Split Capacitor Motors (PSC) are the predominant technology used to power furnace blowers. Typically, they can be installed to operate at one of 3 or four predetermined speeds. A variable speed motor (VSM) can operate through a range of speeds depending on the needs of the heating system.

Exhibit 4.3.1. Has comfort in house increased, decreased or stayed the same.

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	200	100	100	74	111
Increased	67	76	57	58	77
Decreased	1	1	1	1	1
Remained the same	29	21	36	32	21
DK/NR	4	2	6	8	1

Respondents were then questioned to determine in what way comfort increased or decreased. The major factors are: more even temperature; house warmer; quieter; and house more comfortable. Surprisingly, stated differences were small between PSC and VSM motors with the exception of more even temperature and lower noise, both selling points for VSM motors. Two respondents reported decreased comfort due to cool drafts and long cycle times for the furnace.

Exhibit 4.3.2 In what way has comfort increased?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	133	76	57	43	85
More even temperature	59	68	47	49	68
House warmer	26	28	25	35	22
Quiet fan / less noise	15	18	11	9	18
House more comfortable	14	14	14	19	11
Previously cold rooms warmer now	8	7	11	9	6
House heats faster	8	5	11	9	7
Temperature more constant	8	12	2	12	6
Indoor air quality has improved	7	5	9	5	8
Thermostat more effective / easier to use	4	5	2	2	5
Furnace runs for shorter periods	2	1	4	2	2
Drafts have been reduced	2	1	2	0	2
Other	6	4	9	5	7
DK/NR	2	1	4	2	1

Exhibit 4.3.3 In what way has comfort decreased?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	2	1	1	2	0
Cool drafts	50	-	100	-	100
Longer cycle time	50	100	-	100	-

4.4 Supplementary Heating

To help understanding changes in energy consumption associated with the installation of a new furnace, information was collected on the prevalence of supplementary heating, and how the use of supplementary heating changed when the new furnace was installed.

There are two cases to consider. First, if the use of supplementary heating is reduced after the furnace is installed, and if the alternate fuel is not natural gas, then the expected reduction in natural gas consumption may not take place as the heating load on the furnace has increased. Second, if the alternate fuel is natural gas, then the effect on natural gas consumption will depend on the relative efficiency of the secondary heating equipment relative to the high efficiency furnace, but may further increase the savings expected upon the installation of the high efficiency furnace as the heat is now provided by a more efficient appliance.

Exhibit 4.4.1 shows that about 64% of the participants have secondary heating, while Exhibit 4.4.2 shows that natural gas is the predominant fuel. Exhibit 4.4.3 shows the cross tabulation of the heating technologies used to provide secondary heat, and show that fireplaces are the predominant technology for natural gas.

The data in this section is also shown by furnace motor type, but no significant differences were observed.

Exhibit 4.4.1 Does your house have supplementary heating?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	200	100	100	74	111
Yes	64	64	63	61	64
No	37	36	37	39	36

Exhibit 4.4.2. What heating fuel is used for supplementary heating?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	127	64	63	45	71
Natural Gas	57	52	62	49	59
Electricity	29	31	27	29	31
Wood	28	28	29	44	20
Oil	2	2	2	2	1

Exhibit 4.4.3 For supplementary heating, what method is used?

	Total (%)	Participants (%)	Non-participants (%)
Base	51	30	21
Electricity	**24**	**30**	**14**
- Elec. baseboard	14	20	5
- Portable elec.	8	7	10
- Oil heat	2	3	-
- Fireplace	10	13	5
Natural Gas	**63**	**57**	**71**
- Fireplace	55	50	62
- Radiant elec.	2	3	-
- NG. wall heater	4	7	-
- NG stove	4	-	10
- Wood stove	2	3	-
- Elec baseboard	4	7	-
Wood	**24**	**20**	**29**
- Fireplace	12	7	19
- Wood Stove	12	13	10

Note: columns do not sum due to multiple responses

Exhibit 4.4.4 shows the change in use of secondary heating after the installation of the new furnace, and it shows that about 5% of participants increased their use of secondary heating while 47% reduced it. Assuming approximately the same amount of secondary heating usage, this indicates a net reduction of about 42% of secondary heating after the new furnace is installed.

Exhibit 4.4.4 Has your use of supplementary heating changed?

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	127	64	63	45	71
Increased	5	5	5	2	4
Decreased	40	47	33	40	41
Remained the same	50	44	57	56	49
DK/NR	5	5	5	2	6

Respondents were also asked to estimate the amount of the reduction in secondary heating after the installation of the new furnace. Exhibit 4.4.5 shows a reduction of 52% overall, and 50% among program participants.

Exhibit 4.4.5. By how much has your use of supplementary heating decreased

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	51	30	21	18	29
Mean	52	50	55	63	43
0 – 24%	20	23	14	11	28
25 – 49%	20	17	24	22	17
50 – 74%	20	20	19	17	24
75 – 100%	35	33	38	50	21
DN/NR	6	7	5	-	10

4.5 Customer Characteristics

Information was collected on a variety of respondent characteristics. Exhibit 4.5.1 shows the age distribution of respondents. For participants, the largest group was in the age range 46-54 years and the second largest group was in the age range 55-64 years. For non-participants the largest group was in the age range of 65 years and over while the second largest group was in the 55 - 64 years age range. This could indicate that Terasen program promotion is not reaching the older age groups as effectively as it is the "middle aged".

Exhibit 4.5.1. Age of Respondents

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
25-34 years	6	9	2
35-44 years	15	17	12
45-54 years	23	28	17
55-64 years	27	23	30
65 years +	30	22	38
DK/NR	1	1	1

Marital status of respondents is shown in Exhibit 4.5.2. The participant sample has 3% singles, 90% married or common law; 2% divorced or separated; and 3% widowed. The non-participant sample also has 3% single but 75% married or common law; 5% divorced or separated; and 11% widowed.

Exhibit 4.5.2. Marital Status

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Singles	3	3	3
Married/common law	84	90	77
Divorced/separated	4	2	5
Widowed	7	3	11
DK/NR	3	2	4

Highest level of education attained by respondents is shown in Exhibit 4.5.3. The participant sample has larger share of respondents who have post high school education than the non-participant sample.

Exhibit 4.5.3. Highest Level of Education Attained

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Some high school	8	6	9
Completed high school	16	12	19
Some university/college	12	12	11
Completed university/college	30	30	30
Some trade/technical school	4	3	4
Completed trade/technical school	16	20	12
Post graduate	10	11	8
DK/NR	7	6	7

The number of people in the house is shown in Exhibit 4.5.4 with standard errors in parentheses. The total sample has an average of 2.6 people per house, the participant sample an average of 3.1 people per house and the non-participant sample an average of 2.6 people per house. This may reflect the older age group and higher level of widowed people in the non-participant group. To the extent that natural gas usage varies with household size, this indicates that the program is successfully targeting higher natural gas users. This consideration is also reflected in the discrete choice analysis which found that higher natural gas usage was a determinant of program participation.

Exhibit 4.5.4. Number of People in House

	Total	Participants	Non-participants
Base	200	100	100
Average	2.8 (0.1)	3.1 (0.1)	2.6 (0.1)

Note: Standard error in parentheses.

Exhibit 4.5.5 Number of People in House by Age

	Total	Participants	Non-participants
Base	200	100	100
0 – 18	0.6 (0.1)	0.7 (0.1)	0.5 (0.1)
19 – 24	0.2 (0.0)	0.3 (0.1)	0.1 (0.0)
25 – 34	0.2 (0.0)	0.3 (0.1)	0.1 (0.0)
35 – 44	0.3 (0.0)	0.4 (0.1)	0.3 (0.1)
45 – 54	0.5 (0.1)	0.6 (0.1)	0.4 (0.1)
55 – 64	0.5 (0.1)	0.5 (0.1)	0.5 (0.1)
65 and older	0.6 (0.1)	0.4 (0.1)	0.7 (0.1)
DK/NR	5%	8%	1%

4.6 Furnace Characteristics

Respondents were asked a range of questions about the replaced furnaces. The average age of furnaces at time of replacement was about 24.9 years overall, about 24.2 years for participants and about 25.5 years for non-participants. This tends to support that the program encourages people to replace their furnaces earlier than they otherwise would. The share of furnaces working at time of replacement was about 93% overall, with no difference between participants and non-participants.

Exhibit 4.6.1. Characteristics of the Replaced Furnace

	Total	Participants	Non-participants
Base	200	100	100
Age of the furnace at time of replacement (years)	24.9 (0.6)	24.2 (0.9)	25.5 (0.9)
Was furnace working at time of replacement (respondent share stating furnace was working)	93%	93%	93%

Note: Standard error in parentheses.

The efficiency level of the new furnace is shown in Exhibit 4.6.2. All furnaces purchased by participants were of course high efficiency, but the reporting of 7% of these high efficiency furnaces as mid efficiency highlights the difficulty consumers have with understanding the actual efficiency level of their furnace. Sixty percent (60%) of furnaces purchased by non-participants were noted as high efficiency. However, there is some uncertainty as to the accuracy of the reported incidence of high efficiency furnaces by non-participants due to their limited understanding the actual efficiency of the installed furnace.

Exhibit 4.6.2. Efficiency Level of New Furnace

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Mid efficiency	34	7	60
High efficiency	66	92	39
DK/NR	1	1	1

The efficiency level of the previous furnace is shown in Exhibit 4.6.3. About 93% of total respondents had a standard efficiency furnace while 97% of participants and 89% of non-participants had a standard efficiency furnace.

Exhibit 4.6.3. Efficiency Level of Previous Furnace

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Standard efficiency	93	97	89
High efficiency	5	2	7
DK/NR	3	1	4

The capacity of the new furnace is shown in Btus per hour in Exhibit 4.6.4. The average furnace heating capacity for the whole sample is about 80,000 Btuh, for participants is about 78,000 Btuh and for non-participants is about 82,000 Btuh. However the high DK/NR level indicates these numbers are based on a relatively small sub-sample, which raises concerns about the representativeness of the data.

Exhibit 4.6.4. Capacity of New Furnace (Btu per hour)

	Total (BTU)	Participants (BTU)	Non-participants (BTU)
Base	200	100	100
Average	79,966 (2,734)	77,906 (3,677)	82,407 (4,112)
DK/NR	71%	68%	73%

Note: Standard error in parentheses.

Respondents were asked about the behavior of their previous furnace fan as indicated in Exhibit 4.6.5. Before the furnace change, about 9% of all fans ran continuously with this share at 14% for participants and 4% for non-participants. The last two columns show the type of fan motor chosen in the new furnace.

Exhibit 4.6.5. Furnace Fan Behavior Before Furnace Change

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	200	100	100	74	111
Intermittently when providing heat	52	53	51	51	57
Continuously during heating season	8	6	10	9	6
Intermittently when providing heat / AC	12	13	11	11	13
Continuously during heating / AC season	4	1	7	5	4
Intermittently to also provide ventilation	5	5	4	1	7
Continuously	9	14	4	7	12
No furnace fan (boiler)	5	4	5	4	5
DK/NR	6	4	8	11	3

For people who indicated that they also used their fan intermittently to provide ventilation, Exhibit 4.6.6 shows the number of months per year than the furnace is used in this mode.

Exhibit 4.6.6 Months of use to "also provide ventilation"

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	9	5	4	1	8
Intermittently when providing heat	6.5 (1.6)	8.3 (2,6)	4.8 (1.9)	12.0	5.0

Exhibit 4.6.7 shows the furnace fan usage after the furnace is replaced. Of particular note is the reduction in intermittent use when providing heat only and the increase in intermittent use when providing heating and air conditioning. This may be indicative of the installation of central air conditioning at the time the furnace is being replaced. Also the continuous use of ventilation appears to increase for program participants.

Exhibit 4.6.7. Furnace Fan Behavior After Furnace Change

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	200	100	100	74	111
Intermittently when providing heat	39	37	41	43	35
Continuously during heating season	5	5	5	4	6
Intermittently when providing heat / AC	22	18	25	24	18
Continuously during heating / AC season	10	7	12	8	11
Intermittently to also provide ventilation	7	8	5	3	9
Continuously	13	19	6	8	17
No furnace fan (boiler)	2	-	3	4	-
DK/NR	5	6	3	5	4

Exhibit 4.6.8 Months of use to "also provide ventilation"

	Total (%)	Participants (%)	Non-participants (%)	PSC Motors (%)	VSM Motors (%)
Base	13	8	5	2	10
Intermittently when providing heat	6.0 (1.2)	6.3 (1.2)	5.3 (3.4)	5.0	6.1

4.7 Variable Speed Blower Component

A series of questions were asked to better understand VSMs. The primary reasons for selecting VSMs are because of the energy efficiency and because the contractor recommended it. However, there is some reason to think that the non-participant VSM share is overstated as respondents have difficulty differentiating between VSMs and the multiple speed capability of PSC motors. Hence the data should be used with caution. It should also be noted that 10% of the participants with VSMs stated that they wanted continuous ventilation. The data also supports the idea that VSM sales are strongly influenced by the contractor as part of the sales process.

Exhibit 4.7.1 Why did you select a model with a VSM

	Total (%)	Participants (%)	Non-participants (%)
Base	115	69	46
It is more energy efficient	43	49	33
The contractor recommended it	23	19	30
It is quieter	8	10	4
Wanted continuous ventilation	6	10	-
Provides more comfortable ventilation	6	6	7
Keeps my house warmer	4	4	4
Operates through a range of speeds	4	7	-
Wanted better indoor air quality	4	7	-
Was motivated by the $ 150 rebate	4	7	-
Part of the better furnace I wanted	3	1	4
It provides even heat	3	4	-
The price was attractive	3	-	7
Salesman / dealer recommended it	2	1	2
It does not run continuously	1	-	2
Other	9	7	11
No reason in particular	2	1	2
DK/NR	10	10	11

Exhibit 4.7.2 further supports the idea that VSM sales largely develop during the sales process, as only 23% of purchasers were aware of the product prior to installing the new furnace, and only 18% had considered purchase. However participants were more knowledgeable than the non-participants.

Exhibit 4.7.2. Prior to installing this furnace, were you aware of, or considering the purchase of a VSM?

	Total (%)	Participants (%)	Non-participants (%)
Base	115	70	85
Aware of	23	34	14
Considering purchase	18	24	13
No	58	41	72
DK/NR	1	-	1

Exhibit 4.7.3 shows the sources of awareness, and again indicates that the contractors are the single largest source of awareness, and when combined with the sales / dealer component account for 32% of the awareness.

Exhibit 4.7.3. Sources of awareness

	Total (%)	Participants (%)	Non-participants (%)
Base	64	41	23
Contractor	19	17	22
Word of mouth	13	15	9
Salesmen / dealers	13	15	9
Terasen Gas	11	10	13
Internet (general)	9	12	4
Manufacturer's website	8	5	13
My work	6	2	13
Homeshow	5	7	-
Federal government	5	7	-
Newspaper	2	2	-
Other	13	12	13
DK/NR	14	15	13

People who purchased a furnace without a VSM were asked why they had done so. For the total sample, the largest reason is cost at 28% (sum of 'furnace too expensive' plus "too expensive') followed by lack of awareness at 23%.

Exhibit 4.7.4. Reasons for not purchasing a furnace with a VSM

	Total (%)	Participants (%)	Non-participants (%)
Base	40	31	9
Unaware of VSM	23	29	-
Furnace with VSM was too expensive	15	13	22
Contractor did not recommend it	15	13	22
Too expensive	13	10	22
Participant w/ PSC who insisted it was VSM	8	10	-
VSM not available on furnace I choose	5	-	22
Other	5	6	-
Did not need a VSM	5	-	22
DK/NR	18	22	-

4.8 Housing Characteristics

Dwelling type for respondents is shown in Exhibit 4.8.1. Single detached homes dominated the sample, with the share of single detached dwellings at 96% for the whole sample, with no significant difference between participants and non-participants.

Exhibit 4.8.1. Dwelling Type

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Single detached	96	96	95
Semi detached (duplex)	1	2	2
Row/townhouse	2	2	2
Mobile/other	2	2	2

The average age of the house is shown in Exhibit 4.8.2. The average age of dwelling was 29 years overall, 28 years for participants, and 31 years for non-participants, again perhaps reflecting the older age group in the non-participants.

Exhibit 4.8.2. Age of Home

	Total	Participants	Non-participants
Base	200	100	100
Years	29.3 (0.8)	28.0 (1.0)	30.5 (1.1)

Note: Standard error in parentheses.

Exhibit 4.8.3 shows the heated area of the home. The difference in size between participants and non-participants is not statistically significant.

Exhibit 4.8.3. Heated Area of Home

	Total	Participants	Non-participants
Base	200	100	100
Square Feet	2018 (72.7)	2059 (65.0)	1975 (132.6)

Note: Standard error in parentheses.

Natural gas uses in the dwelling are shown in Exhibit 4.20. Main uses are water heating, space heating, fireplaces, secondary space heating, cooking and barbequing. Less important uses are clothes drying, hot tubs, pool heating and patio heaters.

Exhibit 4.8.4. Natural Gas Uses in the Home

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Water heating	86	93	79
Main Space heating	80	76	83
Fireplace insert	50	50	49
Secondary Space heating	45	34	55
Cooking	20	21	18
Barbeque	16	18	14
Clothes drying	7	8	6
Hot tub	2	2	2
Outdoor pool heating	3	4	1
Patio Heater	1	1	-
NR	4	2	6

4.9 Program Design

A number of issues were explored to help with the design of a possible future program, including influencers of heating system choice and importance of the various incentives.

Exhibit 4.9.1 reflects the major influencers on customers' choice of heating system. For the total sample, energy efficiency was the strongest influencer, closely followed by comfort in the home. It is interesting to note that operating cost of the heating system was consistently ranked as more important than the initial cost. Indoor air quality also receives a significant ranking.

Exhibit 4.9.1 Influencers on choice of home heating system

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Energy Efficiency	4.5 (0.1)	4.6 (0.1)	4.4 (0.1)
Comfort in your home	4.4 (0.1)	4.3 (0.1)	4.6 (0.1)
Operating cost of the system	4.3 (0.1)	4.4 (0.1)	4.3 (0.1)
Indoor air quality	4.2 (0.1)	4.2 (0.1)	4.2 (0.1)
Both initial and operating costs	4.1 (0.1)	4.1 (0.1)	4.2 (0.1)
Initial cost of the system	3.9 (0.07)	3.8 (0.11)	4.0 (0.09)

Note: Standard error in parentheses.

A series of questions was asked to determine the relative merits of the $ 300 incentive and the financing plan. Exhibit 4.9.2 shows the shares for the choice of grant vs. the financing program.

Exhibit 4.9.2. Incentive Choice

	Participants (%)
Base	100
$ 300 Rebate	89
Financing	7
DK/NR	4

Exhibit 4.9.3 shows that the primary reason for choosing the grant was that the participants had sufficient funds to pay for the upgrade, or did not want to borrow money.

Exhibit 4.9.3. Reason for choosing $ 300 grant

	Participants (%)
Base	89
Had money to pay for furnace	66
Rebate was of more value to me	15
Do not like finance / get into debt	11
Alternative financing / Sears 0%	3
Too much paperwork	2
Not aware of financing option	2
Other	6
No reason in particular	2
DK/NR	3

Conversely, the people who chose financing were predominantly those who did not have sufficient funds to pay for the upgrade.

Exhibit 4.9.4. Reason for choosing Financing

	Participants (%)
Base	7
Financing was of more value to me	43
Did not have money to pay for furnace	43
Interest rate was more attractive than loan	29
Other	14
DK/NR	14

Exhibit 4.9.5 shows that 57% of the people who chose financing would not have purchased a furnace at this time without the financing plan. This represents an additional 120 furnaces. As furnace sales only increased by 130 units between 2002 and 2003, it can be argued that the finance program was largely responsible for this increase in participation.

Exhibit 4.9.5. Would you have purchased furnace at this time if no finance plan?

	Participants (%)
Base	7
Yes	43
No	57

The 2003 program represented the first time that Homeworks was involved in the program (to provide the financing) and they appear to have done a satisfactory job of meeting participants' expectations.

Exhibit 4.9.6. How satisfied were you with the service provided by Homeworks?

	Participants (%)
Base	7
Extremely satisfied	14
Very satisfied	57
Somewhat satisfied	29

Respondents were asked if they were familiar with the Energy Star label for furnaces. About 51% of the overall sample, 67% of participants and 35% of non-participants were aware of the Energy Star label. This compares with about 43% of the overall sample, 47% of participants and 38% of non-participants from the 2002 survey, and indicates that awareness of the Energy Star label is still increasing.

Exhibit 4.9.7. Familiar with the Energy Star Label for Furnaces

	Total (%)	Participants (%)	Non-participants (%)
Base	200	100	100
Yes	51	67	35
No	46	29	63
DK/NR	3	4	2

Respondents were asked if they found an Energy Star label on the furnace they bought. About 75% of the overall sample, 88% of participants and 51% of non-participants found the Energy Star label. This compares with about 65% of the overall sample, 70% of participants and 59% of non-participants in the 2002 survey and again supports an increasing awareness of the Energy Star label.

Exhibit 4.9.8. Found an Energy Star Label for Furnace that was Purchased

	Total (%)	Participants (%)	Non-participants (%)
Base	102	67	35
Yes	75	88	51
No	10	1	26
DK/NR	15	10	23

Exhibit 4.9.9 shows that participants strongly support the inclusion of Energy Star products in the program.

Exhibit 4.9.9 Importance of including Energy Star products

	Participants
Base	67
Yes	4.6 (0.1)
DK/NR	1%

4.10 Furnace Prices

Respondents were asked the installed price of their new furnace, including any applicable taxes. Exhibit 4.10.1 shows the mean price paid for participants, non-participants who purchased standard efficiency furnaces and non-participants who purchased high efficiency furnaces. The average prices paid were $3176 overall, and $3727 for participants. However the $2528 for non-participants buying standard efficiency furnaces and $2577 for non-participants buying high efficiency furnaces does not appear reasonable when compared with available information on furnace prices. It should be noted that the price difference stated for PSC and VSM equipped furnaces is influenced by the fact that VSMs are almost exclusively found in 2-stage furnaces, while single stage furnaces still predominates the PSC market. Further detail on the distribution of furnaces by price is given in Exhibit 4.10.2.

Exhibit 4.10.1. Furnace Prices (dollars)

	Total (all)	Participants (high efficiency)	Non-participants (mid efficiency)	Non-participants (high efficiency)	Part. PSC	Part. VSM
Base	200	100	60	39	35	65
Mean	3,176	3,727	2,528	2577	2999	4110
Std. error	98.4	124.9	169.0	168.5	157.9	148
DK/NR	21%	16%	30%	21%	17%	15%

Exhibit 4.10.2. Distribution of Furnaces by Price (percentage)

	Total (all)	Participants (high efficiency)	Non-participants (standard efficiency)	Non-participants (high efficiency)
$999 or less	1.0	-	2	3
$1000-$1999	8	3	17	8
$2000-$2999	27	15	33	44
$3000-$3999	17	22	8	18
$4000-$4999	18	31	3	5
$5000-$5999	6	8	3	3
$6000-$6999	3	4	2	-
Over $7000	2	1	-	-
DK/NR	21	16	30	21

4.11 Free Rider and Spill Over Analysis

Program participants were asked how important the Heating System Upgrade Program was in their decision to install a high efficiency furnace, where one was not at all important and five was very important as shown in Exhibit 4.11.1. To summarize the impact of the program, a weighted average of the importance scores was calculated, where the weights were as follows: score of five has weight of 1.00, score of four has weight of 0.75, score of three has weight of 0.50, score of two has weight of 0.25 and score of one has weight of 0.00. The weighted average of the importance scores is one minus the free rider rate, and indicates a free rider rate of about 43%.

Exhibit 4.11.1. Free Rider Analysis – Furnace program

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.20	0.28	0.25	0.12	0.11	
Product	0.20	0.21	0.13	0.03	0.000	0.57

Program participants were asked if they replaced the furnace early because of the availability of the rebate. As Exhibit 4.11.2 indicates 43% of participants indicated that they had replaced the furnaces early by an average of 2.5 years because of the availability of the rebate. Weighted across all respondents, furnaces were replaced an average of 1.08 years early because of the availability of the rebate.

Exhibit 4.11.2. Spill Over Analysis

	Replaced early (%)	Years replaced early	Weighted average years replaced early
Base	100	43	
Yes	43	2.5	1.08
No	53	0.00	0.000
DK/NR	4	-	-
Total participants	-	-	1.08

Those program participants who had chosen the VSM component of the program were asked how important the $ 150 incentive was in their choice of furnace. Using the same methodology as above, the weighted average of the importance scores is one minus the free rider rate, and indicates a free rider rate of 39%.

Exhibit 4.11.3. Free Rider Analysis – VSM component

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.20	0.34	0.26	0.08	0.12	
Product	0.20	0.26	0.13	0.02	0.000	0.61

5. Trade Ally Survey Results

Trade ally support of the program is critical to the transformation of the natural gas furnace market. Terasen's records show that 443 registered contractors provided updates to participate in the program. This represents about 23% of the registered contractors in BC, but a much larger percentage of the furnaces sold. For the 2003 evaluation, the number of Trade Allies surveyed was increased from 20 to 40, and based on the average number of employees this had the effect of including more of the smaller contractors.

5.1 Trade Ally Satisfaction

Trade allies were asked to indicate their level of satisfaction with program components on a five-point scale where one is not at all satisfied and five is very satisfied. Exhibit 5.1.1 shows the reported levels of satisfaction with the standard errors shown in parentheses. Trade allies reported satisfaction levels averaging 4.0 or more for the amount of the rebate and the types of furnaces eligible. They expressed the lowest level of satisfaction with the time period for purchasing an eligible furnace.

Exhibit 5.1.1. Trade Ally Satisfaction with Program (mean on 5-point scale)

	Component 2003
Base	40
Amount of the rebate	4.1 (0.1)
Types of furnaces eligible for a rebate	4.1 (0.2)
Information on the rebate	3.8 (0.2)
Application procedures to obtain the rebate	3.8 (0.2)
Amount of the financing	3.5 (0.3)
Duration of the financing (24 months)	3.5 (0.3)
Information on the financing option	3.4 (0.3)
Time period for purchasing an eligible furnace	2.9 (0.2)

Note: Standard error in parentheses.

5.2 Trade Ally Characteristics

The average number of employees in reporting firms was 5.5 with a standard error of 0.7. This is a decrease from the 2002 survey, where the average number of employees was 8.1.

Exhibit 5.2.1. Number of Employees

	Share 2003 (%)	Share 2002 (%)
Base	40	20
Mean	5.5 (0.7)	8.10 (1.56)
Up to 2	35.0	20.0
3 to 5	24.0	30.0
6 to 11	28.0	20.0
Over 12	13.0	30.0

Note: Standard error in parentheses.

The main type of business is shown in Exhibit 5.2.2. The primary types of businesses were heating contractors, both independent and dealers, followed by plumbing and heating contractors.

Exhibit 5.2.2. Primary Business

	Share (%)
Base	40
Independent heating contractor	38
Furnace dealer & heating contractor	28
Plumbing and heating	15
Gas fitter	8
Mechanical contractor	8
Other	5

5.3 Furnace Characteristics

Trade allies were asked a number of questions about the replaced furnaces. Trade allies indicated that share of operating furnaces increased from 79% in the pre-program period to 84% during the program period as shown in Exhibit 5.3.1. This supports the idea that the program does influence customers to replace furnaces earlier than they might otherwise do.

Exhibit 5.3.1. Share of Furnaces Operational at Time of Replacement

	Share 2003 (Jan-Aug) (%)	Share Pgm (Sep-Dec) (%)
Mean	78.6 (4.6)	83.5 (3.3)
Up to 80%	42	39
81% to 90%	23	18
90% to 100%	33	18
DK/NR	5	45

Note: Standard error in parentheses.

Trade allies were asked to estimate the remaining life of furnaces at the time of replacement. The average remaining furnace life at replacement was estimated at about 5.3 years, slightly higher than the 4.5 years estimated in 2002.

Exhibit 5.3.2. Average Remaining Furnace Life at Replacement

	Share 2003 (Jan-Aug) (%)	Share Pgm (Sep-Dec) (%)
Base	40	40
Mean (years)	5.3 (0.5)	5.4 (0.5)
1 year or less	10	10
1 to 5 years	49	51
6 to 10 years	31	30
Over 10 years	0	0
DK/NR	13	10

Trade allies were asked if they routinely do a heat calculation as part of the pre-installation work. As Exhibit 5.3.3 indicates, about 48% of trade allies routinely do a heat calculation while about 53% of trade allies do not routinely do a heat loss calculation. This is a decrease from the 65% in 2002 who reported that they routinely did heat loss calculations, but may be more reflective of the practices of smaller firms in the 2003 sample than a change in the market practice.

Exhibit 5.3.3. Routinely do Heat Loss Calculation

	Share 2003 (%)
Base	40
Yes	48
No	53

Those trade allies who routinely do a heat loss calculation were asked what share of the time the heat loss calculation leads to a smaller capacity furnace. About 65% of the time, heat calculations leads to installation of a smaller capacity furnace.

Exhibit 5.3.4. Share of Time Heat Loss Calculation Leads to Smaller Capacity Furnace

	Share 2003 (%)
Base	19
Mean	64.6 (10.3)
0%	11
1% to 10%	16
11% to 50%	5
51% to 80%	10
81% to 100%	48
DK/NR	11

Note: Standard error in parentheses.

Respondents were asked to indicate the importance of the three incentives in affecting their customers' choice of furnace, where one is not at all important and five is very important, with standard errors in parentheses. This result shows that the $ 300 grant is considered to have a strong influence, while the financing program has a much lower impact. This is also reflected in the lower uptake on the finance program, which only accounted for about 7% of participation. The VSM incentive was assigned a low importance.

Exhibit 5.3.5. Trade Ally Views of Importance of Factors Affecting Choice of Furnace

	Share 2002 (%)
Base	40
Availability of rebate	4.0 (0.2)
Financing program	2.2 (0.2)
VSM incentive	2.9 (0.2)

Note: Standard error in parentheses.

A number of questions were asked to determine factors affecting trade ally recommendations to customers on choice of furnace. Exhibit 5.3.6 shows that about 17% of the locations are viewed as unsuitable for high efficiency replacement furnaces. This is a decrease from 25% in 2002.

Exhibit 5.3.6. Share of Customers for Which High Efficiency Furnace Not Economic due to Furnace Location

	Share 2003 (%)
Base	40
Mean	17.2 (3.2)
Up to 10%	55
11% to 40%	28
Over 40%	11
DK/NR	8

Note: Standard error in parentheses.

About 68% of trade allies believe that high efficiency furnaces are the best choice for their customers while another 23% believe that high efficiency furnaces are sometimes the best choice for their customers.

Exhibit 5.3.7. Believe that High Efficiency Furnaces Best Choice for Customers

	Share 2003 (%)
Base	40
Yes	68
No	10
Sometimes/depends on customer	23

A further question was asked to determine why contractors expressed these opinions. On the positive side, the main reasons centered on money or gas savings, reliable products and quietness. On the negative side, the primary reason was due to higher cost / longer payback period.

Exhibit 5.3.8. Why do you say this?

	Share (%)
Base	40
They will save money on gas	60
Too expensive / too long to recoup cost	18
They are reliable	13
They are quieter	10
They are easy to set up / install	8
Other furnaces are more reliable / last longer	8
They are better for the environment	5
Depends on the application / house factors	5
Other	15

Sometimes a two-stage furnace mid efficiency furnace is recommended as the preferred option as shown in the next Exhibit 5.3.9.

Exhibit 5.3.9. Recommend Two-stage Mid efficiency Furnaces as Preferred Option

	Share (%)
Yes	45
No	43
Sometimes/depends on customer	13

A further question was asked to determine why contractors expressed these opinions. The two main drivers for two-stage mid efficiency furnaces are: lower cost and "almost as efficient as HE furnace". This latter point is a misconception and perhaps should be addressed by Terasen in contractor communications.

Exhibit 5.3.10. Why do you say this?

	Share (%)
Base	40
They are less expensive	20
They are almost as efficient as HE furnaces	10
High efficiency furnaces are most cost effective	10
They are expensive	8
Quieter than single stage furnace	8
Provides more comfortable ventilation	5
Recommend them with a heat pump	5
Depends on the application / factors in house	5
Our suppliers do not carry them	5
They work better than single stage	5
Work well in this climate	5
We let our customers make the decision	3
Other	10
No particular reason	10

Contractors were asked for the shares of the various types of fan motor technologies sold throughout the year, and also the share of VSM motors sold during the program period. Exhibit 5.3.11 shows that the share of VSM motors increased from about 28% of sales to about 38%, or by about 36%.

Exhibit 5.3.11. Furnace Blower Motors Shares

	During all of 2003			Sep - Dec
	Single Speed PSC (%)	Multi Speed PSC (%)	VSM (%)	VSM (%)
Base	40	40	40	40
Mean*	16.6 (5.3)	55.1 (5.9)	28.2 (4.7)	38.3 (5.8)
0%	73	18	25	23
1% to 20%	8	8	23	13
21% to 50%	6	23	36	36
51% to 80%	5	24	11	8
81% to 100%	10	31	8	18
DK/NR	-	-	-	5

The main features of interest for VSM's are that they use less electricity, they are quieter and they provide more comfortable ventilation. The incentive ranked fourth. However, 10% of the respondents believe that the VSM results in reduced natural gas usage, when in reality it increases the natural gas usage. Again this is something that Terasen may wish to address with contractors.

Exhibit 5.3.13 shows the results of further probing for customer motivations.

Exhibit 5.3.12. VSM Features of interest to customers

	Share (%)
Base	40
Uses less electricity	48
Quieter	33
Provides more comfortable ventilation	15
$ 150 rebate	13
Operates through a range of speeds	10
Uses less gas	10
Other	10
DK/NR	18

Exhibit 5.3.13. Customer motivations to purchase a VSM equipped furnace

	Share (%)
Base	40
Customer wanted continuous ventilation	8
It uses less electricity	8
It uses less natural gas	8
Incentive program / rebate	5
Provides more comfortable ventilation	5
Customer wanted the "best" furnace	3
Contractor / sales person "sold" the feature	3
Other	8
Nothing else	30
DK/NR	28

The next two tables probe Contractors attitudes towards VSMs. Exhibit 5.3.14 shows that 58% of the contractors recommend VSMs while Exhibit 5.3.15 identifies the primary reasons as: uses less electricity, provides more comfort and is quieter. The main reason not to recommend them relates to the higher costs.

Exhibit 5.3.14. Recommend VSMs to Customers

	Share (%)
Base	40
Yes	58
No	18
Sometimes/depends on customer	23
DK/NR	3

Exhibit 5.3.15 Why do you say this?

	Share (%)
Base	40
It uses less electricity	38
It provides more comfortable ventilation	33
Too expensive / takes time to recoup the money	23
Quieter	21
More reliable	8
Depends on the application	5
We let our customers make the decision	5
Our suppliers do not carry them	5
Other	5
No reason in particular	3

5.4 Furnace Fan Usage

A series of questions was asked to determine how customers used their furnace fans prior to replacement, and how the fans were set up to operate in the new furnace. Based on Contractor reporting, the major difference in fan usage occurs in furnaces with VSMs, where the contractors report that there is a 33 percentage point increase in the use of continuous ventilation. This is higher than reported by customers and is further discussed in Section 6.

Exhibit 5.4.1. Furnace Fan Behavior for Existing Installations

	Total (%)
Base	40
Intermittently when providing heat	40.5
Continuously during heating season	7.4
Intermittently when providing heat / AC	9.3
Continuously during heating / AC season	6.9
Intermittently to also provide ventilation	13.8
Continuously	22.0
DK/NR	23.0

Exhibit 5.4.2. Furnace Fan Behavior after Installation of New Furnace

	High Furnace (%)	Mid Furnace (%)	VSM Furnace (%)
Base	40	40	40
Intermittently when providing heat	39.9	45.5	14.4
Continuously during heating season	3.6	7.7	4.0
Intermittently when providing heat / AC	12.3	7.8	10.7
Continuously during heating / AC season	8.7	6.6	14.2
Intermittently to also provide ventilation	9.3	10.2	1.8
Continuously	26.4	22.2	54.9
DK/NR	15.0	23.0	38.0

5.5 Market Characteristics

Trade allies were asked a number of questions pertaining to the market for furnaces. Trade allies estimated that almost 80% of their market involves replacement furnaces. However, it should be noted that the trade allies covered in this research were those who participated in the Terasen program, and survey results pertaining to the new furnace market are not necessarily representative of the new construction market. They may be more reflective of the custom home new market.

Exhibit 5.5.1. Share of Sales Involving Replacement Furnaces

	Shares
Mean share	79.0 (4.5)
Up to 30%	11
31% to 50%	11
51% to 80%	18
81% and more	63

Note: Standard error in parentheses.

Trade allies were also asked to provide information on the composition of their furnace sales by type of furnace. Average respondent share of sales for high efficiency furnaces for new dwellings increased from 17% in 2001 to 28% in 2002 and to 37% in 2003. Average respondent share of sales for high efficiency furnaces for replacement furnaces increased from 38% in 2001 to 46% in 2002 and to 57% in 2003. This is consistent with a shift towards a more efficient furnace market. The shares of sales involving high efficiency furnaces are shown in Exhibit 5.5.2.

Exhibit 5.5.2. Share of Sales Involving High Efficiency Furnaces

	Share new dwellings (%)	Share replace-ments (%)	Weight new dwellings	Weight replace-ments	Weighted share new dwellings	Weighted share replace-ments	Overall
2001	17.2	38.4	0.21	0.79	3.61	30.34	33.95
2002	27.9	45.9	0.21	0.79	5.86	36.26	42.14
2003	37.4	56.7	0.21	0.79	7.85	44.79	52.64

Exhibit 5.5.2 also provides an estimate, albeit a biased one, of the share of high efficiency furnaces in the overall furnace market. The share of high efficiency furnaces increased from some 34% in 2001, to 42% in 2002 and 53% in 2003. For the five years 1996 to 2000, the share of condensing furnaces in Canada had stabilised at about 40 %. We believe that the share of condensing furnaces in the BC market also stabilised but at about 25% for this period. This is a significantly lower level than the national one, but it is a level consistent with the relatively low number of heating degree days in the Lower Mainland and Vancouver Island compared with much of the rest of Canada. A lower number of heating degree reduces the economic benefits of a condensing furnace.

5.6 Barriers and Opportunities

A number of questions explored trade ally perceptions of program barriers and opportunities. About 78% of trade allies felt that customers had enough information to make an informed decision on furnace choice. The two areas that were identified by respondents as requiring more information are: how much they will save on operating costs; and differences between furnaces.

Exhibit 5.6.1. Customers Have Enough Information to Make Informed Decision on Furnace Choice

	Share (%)
Base	40
Yes	78
No	23

Exhibit 5.6.2. Information customers are missing (Furnaces)

	Share (%)
Base	9
Operating costs & savings	57
Differences between furnaces	29
Time to recover investment	14
Cost to convert	14
How quiet they are	14

Similar questions were asked specifically about the furnace blower motor efficiency. The primary areas identified were to provide more information on what VSMs are, how they work, and what are the operating cost savings.

Exhibit 5.6.3. Customers Have Enough Information to Make Informed Decision on Furnace Blower Motor Choice

	Share (%)
Base	40
Yes	78
No	23

Exhibit 5.6.4. Information customers are missing (VSM)

	Share (%)
Base	9
What VSMs are and how they work	44
How much they will save	44
Time to recover investment	11
How to track power consumption	11
Heat loss calculation for their house	11

5.7 Program Design

Several issues of relevance to design of a future program were explored in the survey. The peak quarter for sales is October to December when over 50% of the furnaces for a given year are sold. If September is included, then it appears likely that over 60% of the furnaces are sold during the typical Terasen program period.

Exhibit 5.7.1. Peak Quarters for Furnace Sales

	Share of respondents Choosing this quarter
Base	40
January - March	15.3 (1.7)
April – June	12.5 (1.5)
July – September	21.8 (3.3)
October – December	50.3 (3.9)
DK/NR	3%

* Standard Error in paranthesis

Some 70% of trade allies were familiar with Energy Star furnaces as indicated in Exhibit 5.28, while 86% of those familiar with Energy Star recommend them.

Exhibit 5.7,2. Familiar with
Energy Star for Furnaces

	Share (%)
Base	40
Yes	70
No	30

Exhibit 5.7.3. Recommend
Energy Star for Furnaces

	Share (%)
Base	28
Yes	86
No	11
Sometimes / depends on customer	4

In response to a request for suggestions on how customers could be encouraged to install high efficiency furnaces, the main suggestions were: continue / expand the rebate program (38%), provide more information on HE furnaces (10%) and provide more information on energy savings (10%).

Exhibit 5.7.4. Suggestions on How Customers
Could be Encouraged to Install High Efficiency

	Share (%)
Base	40
Expand / continue rebate program	38
More information on benefits of HE furnaces	10
More information on energy savings	10
Increase amount of rebate	8
Increase advertising	5
More incentives for contractors / servicing credit	5
Improve financing option	5
Reduce the cost of HE furnaces	3
No	28

A similar question was asked abut the VSMs. Primary suggestions were: provide more information about savings (20%), expand / continue the rebate program (15%), and increase advertising (10%).

Exhibit 5.7.5. Suggestions on How Customers
Could be Encouraged to Install VSMs

	Share (%)
Base	40
More information about savings	20
Extend / continue the rebate program	15
Increase advertising	10
Reduce the cost of VSMs	8
Increase the rebate amount	8
Promote how quite they are	8
Provide more information about the benefits	3
Other	3
No	33

5.8 Furnace Prices

Trade allies were asked to estimate typical equipment and installed prices for a 90,000 Btuh mid efficiency furnace, a 90,000 Bthu high efficiency furnace and a 75,000 Btuh high efficiency furnace. The 75,000 Btuh furnace provides approximately the same heating capability as the 90,000 Btuh mid efficiency furnace. The results are shown in Exhibit 5.8.1.

Exhibit 5.8.1. Equipment Price and Installed Price for
90 MBtuh mid efficiency and 75 MBtuh high efficiency Furnace (2003)

	90,000 Btuh		75,000 Btuh
	Mid efficiency (dollars)	High efficiency (dollars)	High efficiency (dollars)
Base	40	40	40
Equipment price	1104 (72.8)	1806 (99.3)	1648 (139)
Installed price	2289 (109.0)	3197 (131.0)	2897 (160)

Note: Standard error in parentheses.

5.9 Free Riders and Spill Over Analysis

Trade allies were asked how important the Heating System Upgrade Program was in the customers' decisions to install a high efficiency furnace, where one was not at all important and five was very important as shown in Exhibit 5.9.1. To summarize the impact of the program, a weighted average of the importance scores was calculated, where the weights were as follows: score of five has weight of 1.00, score of four has weight of 0.75, score of three has weight of 0.50, score of two has weight of 0.25 and score of one has weight of 0.00. The weighted average of the importance scores is one minus the free rider rate of about 0.76.

Exhibit 5.9.1. Free Rider Analysis - rebate

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.45	0.28	0.18	0.05	0.05	
Product	0.45	0.21	0.09	0.01	0.00	0.76

Exhibit 5.9.2 provides a second analysis for spill over. The share of furnaces replaced early comes from the consumer survey, but the years replaced early comes from the trade ally survey. The weighted average years replaced early using this approach is 2.322 years.

Exhibit 5.9.2 Spill Over Analysis

	Replaced early (%)	Years replaced early	Weighted average years replaced early
Yes	43	5.4	2.322
No	53	0.00	0.000
DK/NR	4	-	-
Total participants	-	-	2.322

A similar set of questions was used to determine Contractors opinions of the financing program and the VSM incentive. As shown below, the weighted average of the importance scores is about 0.30 for the financing program and 0.56 for the VSM incentive.

Exhibit 5.9.3. Free Rider Analysis - financing

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.06	0.13	0.16	0.22	0.44	
Product	0.06	0.10	0.08	0.06	0.00	0.30

Exhibit 5.9.4. Free Rider Analysis - VSM

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.25	0.16	0.25	0.25	0.20	
Product	0.25	0.12	0.13	0.06	0.00	0.56

6. Impact Analysis

6.1 Furnace Fan Usage

Both Customers and Trade Allies were asked a series of questions to determine their usage of furnace fans both before and after the furnaces were replaced.

Exhibit 6.1.1 summarizes the before and after usage as reported by Customers. To facilitate comparison, the separate responses for the "heating" or the "heating and cooling" period shown in previous tables have been combined. The Before columns show the furnace fan usage by both participants and non-participants prior to replacing the furnace. The PSC and VSM columns show the response of those people who subsequently purchased furnaces with either PSC or VSM blowers. It shows that people who were using the existing furnace blower for ventilation (+6%) or for continuous ventilation (+5%), were more likely to have purchased furnaces with VSMs, and hence indicates that Customers with higher blower usage tended to move to VSMs.

The second part of Exhibit 6.1.1 shows the reported blower usage after the new furnace was installed. It shows that blower usage has increased, as the share of intermittent usage has declined from 73 to 64 while the higher usage categories have increased. However the more dramatic change is in the blower usage by people with VSMs, where intermittent usage is now 20% lower than for people with PSC motors. This indicates that VSMs are reaching the intended audience of higher furnace blower users.

Exhibit 6.1.1. Furnace Fan usage (Customer Survey)

	Before				After			
	Total (%)	PSC (%)	VSM (%)	Dif (%)	Total (%)	PSC (%)	VSM (%)	Dif (%)
Intermittent (heat / cool season)	73	73	69	-4	64	75	55	-20
Continuous (heat / cool season)	13	17	11	-6	15	13	18	+5
Also ventilation	5	2	8	+6	7	2	9	+7
Continuous	10	8	13	+5	13	9	18	+9

Exhibit 6.1.2 shows data from the Trade Ally survey. In this case the data doesn't split out VSM in the same way. The before and after data reflects all furnaces (including VSM) while VSM reflects only those new installations of furnaces with VSMs. This data shows a quite similar pattern of furnace usage before and after the installation of the new furnace. However the Trade Allies are reporting that over 50% of the VSM equipped furnaces are installed for continuous ventilation.

The discrepancy between the Customers reported usage and the Trade Ally reported usage is quite surprising, especially regarding the continuous usage. However the common pattern between the two groups is the significantly higher fan usage among people who have installed VSMs.

Exhibit 6.1.2. Furnace Fan Usage (Trade Ally Survey)

	All Furnaces		VSM
	Before (%)	After (%)	Only (%)
Intermittent (heat / cool season)	50	52	25
Continuous (heat / cool season)	14	13	18
Also ventilation	14	10	2
Continuous	22	25	55

6.2 Furnace Prices

One of the indicators of market transformation is the reduction of prices, or at least of price premiums, for energy efficient products to the consumer. Exhibit 6.2.1 reproduces the furnace pricing from the Trade Ally survey, while Exhibit 6.2.2 shows the comparable data from the 2002 survey.

The two tables appear to indicate a general price increase between 2002 and 2003. However this increase is small, and not statistically significant. Further, as the 2003 survey includes smaller firms, the data may mask higher buying power, and hence lower prices for larger firms.

Exhibit 6.2.1. 2003 Furnace Prices (Trade Ally Survey)

	90,000 Btuh		75,000 Btuh
	Mid efficiency (dollars)	High efficiency (dollars)	High efficiency (dollars)
Base	40	40	40
Equipment price	1104 (72.8)	1806 (99.3)	1648 (139)
Installed price	2289 (109.0)	3197 (131.0)	2897 (160)

Note: Standard error in parentheses.

Exhibit 6.2.2. 2002 Furnace Prices (Trade Ally Survey)

	90,000 Btuh		75,000 Btuh
	Mid efficiency (dollars)	High efficiency (dollars)	High efficiency (dollars)
Equipment price	1068 (52.0)	1596 (105)	1504 (116)
Installed price	2194 (81)	3121 (115)	3071 (129)

Note: Standard error in parentheses.

From the perspective of market transformation, a key issue is the incremental cost of installing the efficient product. As the output of a 90,000 BTU mid efficiency furnace is essentially the same as the output of a 75,000 high efficiency furnace, this is the relevant comparison. Exhibit 6.2.2 shows the change in incremental cost to install a high efficiency furnace in 2003 vs. 2002, and shows that the incremental cost has dropped by 30% over the two years. Assuming a current natural gas price of $ 12.35 per GJ, and an energy reduction of 12.6 GJ per year, this approximates a payback of 5.6 years in 2002 dropping to 3.9 years in 2003.

Exhibit 6.2.3. Comparison of Installed Furnace Prices

	90,000 Btuh	75,000 Btuh	Incremental
	Mid efficiency (dollars)	High efficiency (dollars)	Cost (dollars)
Installed price - 2003	2289	2897	608
Installed price - 2002	2194	3071	877

6.3 Impact of Secondary Heating on Natural Gas Savings

The Customer survey determined that, after the new furnace was installed, about 5% of program participants increased their use of secondary heating while about 47% reduced the secondary heating, and the reduction was by about 50%. The concern is whether this change in the use of secondary heating is affecting the billing analysis estimates of program savings. For example, if more of the space heating load is shifted to the furnace by a reduction of non-natural gas fueled secondary heating, then the billing analysis may understate the impact of the program.

The Customer survey determined that 66% of the secondary heating is from natural gas, 28% from electricity and 19% from wood[5]. Further, 70% of the natural gas secondary heat is from fireplaces. If we make the following assumptions, then we can estimate the net impact of the change in secondary heating on overall natural gas usage.

- The consumption of a natural gas fireplace is about 16 GJ per year (2002 REUS).
- The equivalent AFUE of the average natural gas fireplace is about 50%.
- Electric and wood secondary heat provide the same proportion of total space heat as the natural gas secondary heat (ie: 16GJ @ 50% efficiency or 8GJ of output heat)
- Those who increased secondary heating usage (5%) had approximately the same consumption as those who decreased usage (47%), for a net reduction of 42%.

Exhibit 6.3.1. Change in Natural Gas Consumption from Secondary Heating

	Output Energy (GJ)	Share Secondary Heat (%)	Net Output Energy (GJ)	Furnace Input Energy (AFUE 92) (GJ)	Share Secondary Heat	Unit Impact (GJ)
Electric	8	28	+2.24			
Natural Gas	8	66	-5.28			
Wood	8	19	+1.52			
Total			-1.52	-1.66	0.42	-0.70

As shown in Exhibit 6.3.1, the potential impact from the reduction in secondary heating after the installation of the high efficiency furnace appears small, in the order of -0.7 GJ per year. Given the significant assumptions required for this analysis, it was concluded not to include any impact from secondary heating in the program impacts.

6.4 Program Attribution – Discrete Choice

In many program evaluations, program impact is measured as the difference between outcomes for a treatment group (or set of program participants) and a control group (or set of program non-participants). Program impact is then estimated by the "difference of differences" approach where estimated impact is defined as average participant change minus average non-participant change. Here the underlying assumption is that the non-participant change estimates the change that the participants would have experienced on average in the absence of the program[6]. This method works best if there is random assignment to the

[5] The data in Exhibit 4.4.3 has been adjusted for the reporting of multiple responses.

[6] This methodology, while commonly used in DSM program evaluations does not

treatment and control groups, as is often the case in medical and social experiments.

In DSM evaluations random assignment to treatment and control groups is very difficult. For example, participation in the Residential Heating System Upgrade Program is voluntary so that there is potentially an element of self-selection involved. Self-selection in this context means that those who participate in the program may be more likely than average to install energy efficient measures than the average person even in the absence of the program.

There are two main ways of dealing with self-selection: the survey approach and the discrete choice theory approach. In the survey approach, a sample of participants is asked how likely they would have been to install the efficient measure in the absence of the program. Sometimes, responses are weighted to provide an estimate of the free rider rate. However, this method may result in inaccurate estimates because respondents may assume they would have purchased the efficient technology without the program in place, even though this may not be the case. Respondents may also give answers that they think the interviewer wants to hear. Further, respondents are often not conscious of all the factors that lead them to make a specific purchasing decision. Therefore, too much or too little emphasis may be given to the program, when in fact other variables may have played a key role in influencing customer behavior.

Many of these problems can be minimized by using discrete choice analysis (DCA) to estimate program attribution. DCA enables the attribution rate to be estimated based on objective data (explanatory variables), instead of the subjective responses of customers. In DCA, probit or logit regression methods are typically used to estimate the probability of purchasing an efficient technology based on key explanatory variables. Data is collected on customers' observed purchasing behaviour as well as on several explanatory variables. Then probit or logit regression is used to estimate an equation that relates the observed purchasing behaviour to the explanatory variables. This probit or logit equation can then be used to predict the probability that a customer will purchase an efficient technology based on the levels of the explanatory variables for that customer. This approach was used to estimate the attribution to the furnace program.

Model 1: Choice to participate in the high efficiency furnace program

In modeling the determinants of participation in the high efficiency furnace

---

consider that, in the case of a furnace replacement program, the customer would likely purchase a new furnace in the near future (when the existing unit failed). As the minimum furnace standards were increased in 1995, the new furnace would be more efficient than the existing unit, but not necessarily as efficient as the program induced unit. This issue cannot be addressed purely in a billing analysis as data on the remaining life of the furnace at the time it was replaced is required. This information was available from the survey work done to support the 2003 programs, and is included in this report.

program, the relevant literature suggest that key determinants of the decision to participate might include the amount of energy consumed prior to the program period, attitudes towards energy efficiency, and attitudes towards heating system costs. We also considered income, size of the home, and other variables that proved to degrade the statistical fit of the model. This suggests the model shown in (1) which we model using a probit equation, where households are indexed by the subscript i.

(1) program $participation_i = f(consumption_i, importance\_EE_i, importance\_cost_i)$

The variables are defined as follows:

- *program participation* takes the value "1" for program participants and "0" for program non-participants;
- *consumption* is the weather normalized annual consumption prior to the program period;
- *importance_EE* is the importance of energy efficiency on the household's choice of heating system (measured on a scale from 1 to 5);
- *importance_cost* is the importance of the total system cost (initial plus operating) on the household's choice of heating system (measured on a scale from 1 to 5).

Model 2: Choice to install a high efficiency furnace
In modeling the determinants of installation of a high efficiency furnace, the relevant literature suggest that key determinants of the installation decision might include program participation, the amount of energy consumed prior to the program period, attitudes towards energy efficiency, and attitudes towards heating system costs. We also considered income, size of the home, and other variables that proved to degrade the statistical fit of the model. This suggests the model shown in (2) which we model using a probit equation, where households are indexed by the subscript i.

(2) high $install_i = g(program\ participation_i, consumption_i, importance\_EE_i, importance\_cost_i)$

The variables are defined as follows:

- *high install* takes the value "1" for those installing a high efficiency furnace during the program period and "0" otherwise;
- *program participation* is a dummy variable that takes on the value "1" for participants and the value "0" for non-participants;
- *consumption* is the weather normalized annual consumption prior to the program period;
- *importance_EE* is the importance of energy efficiency on the household's choice of heating system (measured on a scale from 1 to 5);
- *importance_cost* is the importance of the total system cost (initial plus operating) on the household's choice of heating system (measured on a scale from 1 to 5).

RESULTS

Model 1: Choice to participate in the high efficiency furnace program
As noted above, we model the determinants of program participation in the high efficiency furnace program as a function of the weather normalized annual consumption prior to the program period, attitudes towards energy efficiency, and attitudes towards heating system costs (equation 1). This equation was estimated using a probit model. The model was fit using weighted data to correct for the over-representation of program participants in the customer survey sample.[7]

Exhibit 6.4.1 shows the results of the probit regression. For each variable the values of the coefficient, the standard error, the t-statistic and the partial effect are shown, where the partial effect measures the change in the probability of participation due to a one unit change in the independent or driving variable. Also shown are the chi-squared statistic and the share of outcomes correctly predicted by the model, which are measures of goodness of fit for non-linear equations like the probit.

The model fit is good with 51.0% of the outcomes correctly predicted. Increases in pre-program consumption, importance of energy efficiency, and importance of total system cost all lead to an increase in the probability of program participation.

Exhibit 6.4.1. Determinants of Program Participation

	Coefficient	Standard Error	T-statistic	P-Value	Partial Effect
Constant	-.67	.103	-6.47	.00	-.197
Consumption	.00056	.00029	1.93	.053	.00017
Importance_EE	.00030	.00074	.41	.68	.00009
Importance_Cost	.00036	.00051	.70	.49	.00010
Chi-squared [3 df]	7.14			.068	
Share Correct (%)	51.0%				

Model 2: Choice to install a high efficiency furnace
We model the determinants of installation of a high efficiency furnace as a function of program participation, weather normalized annual consumption prior to the program period, attitudes towards energy efficiency, and attitudes towards heating system costs (see equation 2). This equation was estimated using a probit model. The model was fit using weighted data to correct for the over-representation of high efficiency furnace installations in the customer survey

[7] 49% of households in the customer survey were program participants. In comparison, only 23% of households in the total 2003 retrofit market were program participants (assuming approximately 13000 total furnace installations and 2915 total program participants). Therefore, the survey data were weighted to correct for the unrepresentative nature of the sample.

sample.[8]

Exhibit 6.4.2 shows the results of the probit regression. The model fit is good with 80.3% of the outcomes correctly predicted. Households who participated in the program were much more likely to purchase a high efficiency furnace than those who did not participate. Additionally, increases in pre-program consumption and importance of total system cost lead to an increase in the probability of purchase of a high efficiency furnace; while an increase in importance of energy efficiency leads to a decrease in the probability of purchase of a high efficiency furnace. Note however that the coefficients on pre-program consumption, importance of energy efficiency, and importance of total system costs are not statistically significant.

For our purposes, the most important information in the table is the partial effect on the participation variable because this gives us the net to gross ratio. The net to gross ratio is the share of purchases of high efficiency furnaces attributable to the incentive program. The net to gross ratio is 72.3%, which says that about 72% of purchases of high efficiency furnaces during the program period are actually attributable to the incentive program. In perhaps more familiar terms, this means that the net effect is 72% and the free rider rate minus the spill over rate is 28% (using the expression, net effect = gross effect minus free rider rate plus spill over rate).

Exhibit 6.4.2. Determinants of Furnace Choice

	Coefficient	Standard Error	T-statistic	P-Value	Partial Effect
Constant	-.58	.13	-4.38	.00	-.0048
Participation	8.24	.13	63.56	.00	.723
Consumption	.00011	.00030	.36	.72	.00000
Importance_EE	-.00025	.00068	-.37	.71	.00000
Importance_Cost	.00012	.00054	.23	.81	.00000
Chi-squared [4 df]	132.71			.00	
Share Correct (%)	80.3%				

6.5 Energy Savings and Peak Reduction

To estimate energy savings, unit savings are multiplied by the number of gross participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio to provide the estimate of net savings.

Two sources of information were used for this analysis. The first was data from the customer survey, the second from the trade ally survey. The differences

[8] 69% of households in the customer survey installed a high efficiency furnace. In comparison, only 57% of households in the total 2003 retrofit market installed a high efficiency furnace (based on results from the trade ally survey). Therefore, the survey data were weighted to correct for the unrepresentative nature of the sample.

between the data are that the customer survey indicated a different period of time for early replacement. It was felt that the trade ally survey provided better information on the remaining life of the furnace, due to the greater expertise of the trade relative to homeowners, and this estimate has been used in the report.

Three approaches to determining program attribution were considered, (1) responses to customer survey questions, (2) responses to trade ally survey questions, and (3) the Discrete Choice approach discussed in the previous section. These different approaches provided an attribution of 57% from the Customer survey, 76% from the Trade Ally survey and 72.3% from the Discrete Choice analysis. The Discrete Choice estimate was used as this approach is typically less biased and better reflects the impact of the overall program rather than just the incentive component. Estimated net savings are 37.4TJ for the first 5.4 years and 26.6TJ for the subsequent years.

Exhibit 6.5.1. Energy Savings – customer survey

	Unit savings (GJ)	Gross participants	Gross savings (TJ)	Net to gross ratio	Net savings (TJ)
Direct	12.60	2,915	36.729	0.723	26.555
Spill over	8.68	1,253	10.876	1.000	10.876
Annual - first 5.4 years	-	-	-	-	37.431
Annual - subsequent years	-	-	-	-	26.555

In order to estimate peak savings, we assume that heating load on any day is proportional to heating degree days for that day, so that in the coldest month (January) the average daily heating load is (annual heating load in GJ)*(monthly share of annual heating degree days for January)*(1/31 days). The change in peak day load is then estimated as the change in average daily load for January. Exhibit 6.6 calculates the weighted peak day heating load share for January using a representative weather station for each zone and the thirty-year typical meteorological year heating degree-day shares for January. Estimated peak day savings is then weighted peak day heating load share for January multiplied by net savings. Estimated peak day savings are 0.20TJ for the first 5.4 years and then 0.15TJ for subsequent years.

Exhibit 6.5.2. Peak Day Savings

Zone	Representative weather station	Zone customer share	Peak day heating load share	Weighted peak day heating load share	Peak day savings first 4.5 years (TJ)	Peak day savings subsequent years (TJ)
Zone 1	Vancouver	0.244	0.00501	0.00122	-	-
Zone 2	Burnaby	0.173	0.00511	0.00084	-	-
Zone 3	Surrey	0.280	0.00510	0.00143	-	-
Zone 4	Kamloops	0.117	0.00625	0.00073	-	-
Zone 5	Cranbrook	0.186	0.00667	0.00124	-	-
Total		1.000		0.00546	0.2044	0.1450

6.6 Carbon Dioxide Reductions

Natural Resources Canada and Terasen Gas use emissions factors of 50.45 tonnes of carbon dioxide per terajoule and 50.00 tonnes of carbon dioxide per terajoule respectively. Exhibit 6.7 shows the reductions in carbon emissions under the assumption of an emissions factor of 50 tonnes per TJ.

Exhibit 6.6.1. Carbon Dioxide Emissions Reductions

	Net savings (TJ)	Emissions factor	CO_2 reductions (ktonnes)
Direct	26.555	0.05000	1.3278
Spill over	10.876	0.05000	0.5438
Total first 5.4 years	37.431	0.05000	1.8716
Total subsequent years	26.555	0.05000	1.3278

7. Conclusions

Conclusion 1: customer and trade ally satisfaction with the program:

Maintaining high levels of customer satisfaction is a key concern of program management and staff. Satisfaction with a variety of program components was rated on a five-point scale where one is not at all satisfied and five is very satisfied. Participants reported satisfaction levels averaging 3.8 or more for application procedures, information on the rebate, information abut efficient furnaces and types of furnaces eligible for the rebate. Lower levels of satisfaction were expressed for the time period of the program and the amount of the rebate, but these are 3.7 and still quite positive. Trade Allies reported satisfaction of 3.8 or higher for the amount of the rebate, types of furnaces eligible for a rebate, information on the rebate and application processing. The program has achieved high levels of customer and trade ally satisfaction.

Conclusion 2: impact of marketing / advertising of program:

Advertising and promotional activities are a key means of increasing program awareness and participation. For participants and non-participants, the main sources of awareness are: the insert in the Terasen Gas bill, the heating contractor and word of mouth. However, with the exception of bill inserts, these sources of awareness are all quoted at lower levels by non-participants. Compared with the 2002 evaluation, awareness of the program by non-participants has declined from about 41% to 31%. At the same time it appears that the demographics of non-participants have also changed. In 2003 over 68% of the non-participants were age 55 and over whereas in 2002 only 50% fell into this category. This shift in demographics may indicate a need for different strategies to reach the older age groups. A second possible cause for the decline in awareness is that in 2002, the Furnace Tune-up program had 45,000 participants which may have generated broader awareness of all Terasen programs.

Conclusion 3: effectiveness of financing vs rebates as incentives:

The 2003 program included a finance option for the first time. Analysis of program records indicates that only 211 of the 2,915 participants, or about 7%, took advantage of the option. However 57% of these people, or 120 participants indicated that, without the financing option, they would not have purchased a new furnace at this time. Therefore it can be concluded that the finance option increased the program sales by about 4%, or about the total increase in sales between 2002 and 2003.

Conclusion 4: installed prices of mid and high efficiency furnaces (HEF):

One of the indicators of market transformation is the reduction of prices, or at least of price premiums, for energy efficient products to the consumer. While there is some indication of a general price rise for all furnaces between 2002 and 2003, there also appears to have been a decrease in the incremental installed price of a high efficiency furnace relative to a mid efficiency furnace. The incremental price has dropped from $877 to $608, or about 30%. This is the equivalent of a reduction in payback period from 5.6 years in 2002 to 3.9 years in 2003.

Conclusion 5: program impact on sales of high efficiency furnaces:

Three approaches to determining program attribution were considered, (1) responses to customer survey questions, (2) responses to trade ally survey, and (3) the Discrete Choice approach discussed in the previous section. These different approaches provided an attribution of 57% from the Customer survey, 76% from the Trade Ally survey and 72.3% from the Discrete Choice analysis. The Discrete Choice estimate was used as this approach is typically less biased and better reflects the impact of the overall program rather than just the incentive component.

Conclusion 6: program impact on sales of variable speed blower motors (VSM):

Impact of the program on sales of VSMs is less clear than for high efficiency furnaces. Both Customers and Trade Allies were asked about the importance of the program in their choice of furnace with VSM. The Customers' survey indicated an attribution rate of 61% to the program while the Trade Allies indicated a lower rate of 50%. However a comparison of adoption rates between participants and non-participants showed an increase in sales to participants of about 41%.

Conclusion 7: usage of furnace blowers before and after the furnace replacement:

Customers and Trade Allies were queried about the use of their furnace blowers before and after the installation of the new furnace. Analysis of the Customer data shows that people who were making use of the furnaces to provide various levels of ventilation (ie: not just when the system is providing heating or cooling) were more likely to buy a furnace with a VSM. Data on blower usage after the furnace was installed shows that usage of the blower only when providing heating or cooling declined from 73% to 64% with more intensive uses of the blower increasing by a similar amount. However most of this increased blower usage is going to furnaces with VSMs. For example, when comparing blower usage before the furnace installation with just those people who installed VSMs the usage when only providing heat or cooling declines from 73% to 55%. The Trade Ally data confirms these trends, but shows an even stronger shift to continuous ventilation.

Conclusion 8: change in the use of secondary heating after installation of HEF furnace:

The Customer survey determined that 42% of participants decreased their use of secondary space heating after installing the new furnace while only 5% increased their usage. If the fuel is other than natural gas, a reduction in secondary heating will increase the load on the furnace. However if the secondary heating fuel is natural gas, and the secondary heating source is less efficient that the furnace, a reduction in secondary heating will increase the natural gas savings as the load is picked up by the more efficient furnace. The potential impact from the reduction in secondary heating after the installation of the high efficiency furnace appears small, in the order of -0.7 GJ per year. Given the significant assumptions required for this analysis, it was concluded not to include any impact from secondary heating in the program impacts.

Conclusion 9: determinants of HEF program participation:

The discrete choice analysis for the overall furnace program found that the primary determinants of program participation were: consumption of natural gas; importance of energy efficiency and importance of costs. This is also reflected by survey questions on the importance of various influencers on heating system choice (measured on a 5 point scale) which included: energy efficiency (4.5); comfort (4.4); and operating cost (4.3).

Conclusion 10: determinants of VSM incentive participation:

The primary drivers for participation in the VSM incentive component of the program were: energy efficiency (49%); contractor recommendation (23%); quieter operation (10%) and wanting continuous ventilation (10%).

Conclusion 11: discrete choice based estimates of energy savings:

To estimate energy savings, unit savings are multiplied by the number of gross participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio. Estimated net savings are 37.4TJ for the first 5.4 years and 26.6TJ for subsequent years. Estimated peak day savings are the weighted peak day heating load share for January multiplied by net savings. Estimated peak day savings are 0.20TJ for the first 5.4 years and then 0.15TJ for subsequent years.

Conclusion 12: discrete choice based estimates of carbon dioxide reductions

Using an emissions factor of 50 tonnes of carbon dioxide per terajoule yields an emissions reduction or carbon dioxide savings of 1.87 kilotonnes of carbon dioxide for the first 5.4 years of the program and 1.33 kilotonnes of carbon dioxide for subsequent years of the program.

Conclusion 13: status of market transformation in the BC furnace market:

Two indicators of market transformation are considered in this evaluation, changes in market share of high efficiency furnaces over time and changes in customer payback, with increasing market share and improving payback being considered as indicators of market transformation.

- Market share of high efficiency furnaces in the retrofit segment has increased from about 38% in 2001 to about 57% in 2003 while the estimate of the overall market served by Trade Allies included in the study has increased from 29% to about 52%.

- Based on typical furnace prices provided by the Trade Allies, it appears that the incremental cost of installing an high efficiency furnace relative to a mid efficiency furnace has dropped between 2002 and 2003, with a reduction in payback period to the customer dropping from 5.6 years to 3.9 years.

These indicators suggest that the program has made substantial progress in transforming the market for furnaces in B.C.

Appendix A – Weather Normalization Methodology

The weather normalization of the billing data used for this project was developed by Terasen Gas. This description of the weather normalization process was provided by Mr. Lee Robson of Terasen Load Forecast Group.

When normalizing consumption with respect to weather for Rate 1 customers, the following methodology is followed:

1. Obtain consumption history, ensuring at least twelve months consumption is available per period (period being "pre" and "post" installation periods). This provides a number of read dates, consumption and the number of days over which consumption occurred. The consumption figures are converted so that they provide an average daily consumption (total consumption / read days = average consumption).

2. Obtain the HDD's (Heating Degree Days – both using a 13 degree and 18 degree heating day) covering the entire period in question. The average HDD's (both 13 and 18) are matched to the dates in (1), to provide both average consumption and average HDD's.

3. Run the following regression model:

   AvgConsumption = Alpha + (Beta1 X AvgHDD13) + (Beta2 X AvgHDD18) + Error

4. The parameters Alpha, Beta1, and Beta2 from the above regression are then applied to the total HDD's (13 and 18) that would be experience during a "normal" year (which is basically the average of the HDD's over the past 10 years), and this results in a "normalized consumption". The actual formula applied to the parameters calculated in (3) is:

   Normal Consumption = (365 X Alpha) + (TotalHDD13 X Beta1) + (TotalHDD18 X Beta2).

Appendix B – Billing Data Screening

This description of the billing data screening process was provided by Mr. Lee Robson of Terasen Load Forecast Group.

For each premise, consumption information is obtained for a period of 500 days both prior to and after the installation date.

Using the bi-monthly meter reads (and associated consumption), the average daily consumption per meter read is determined. The average daily HDD13 and HDD18 for that same period is also determined. Then run the following regression model is run:

Average Daily Consumption = B0 + (B1 X HDD13) + (B2 X HDD18)

The total HDD13's and HDD18's during a "normal" year (basically the average of the past ten years) are determined and a normalized annual consumption is calculated by:

Normal Consumption = (365 X B0) + (TotalHDD13's X B1) + (TotalHDD18's X B2)

The above calculations are performed on the "pre" and "post" consumption separately.

The following elimination criteria are then applied which provides the finalized list:

1. Only keep those customers that have been in the same premise for at least one year prior to and after the installation date.
    - As different customers have different consumption requirements, a bias would be introduce bias if this screen wasn't used.

2. Only keep those customers where the regressions give an R-Square value > 75%
    - This ensures the model (consumption as a function of heating degree days, both 13 and 18) is a good fit – a value of 75% or greater implies that ¾ of the variation in the model is explained by the model.

3. Only keep those customers where the heatslope coefficient is positive (HDD18)
    - As customers should consume more gas as the heating degree days increase, this screen removes those customers that show less consumption as heating degree days increase.

4. Only keep those customers who have an actual annual consumption > 30GJ

- The average heating load for a Terasen customer is 68 GJ (2002 REUS). This screen eliminates customers who would appear to be using natural gas only for non-heating uses or as secondary heat.

5. Only keep those customers where the EDF (Error Degrees of Freedom) > 3 (which means we have at least five meter reads for that customer)
   - This filters out suspect meter reads, which are meter reads where the transaction period refers back to a date prior to the last read date output (ie. The read date less the corresponding read days is before the last read date). Meter reads are also filtered out where the consumption is zero. For at least one years' worth of consumption, there should be at least 6 meter reads – therefore this screen basically ensures we haven't skipped over more than one meter read.

6. Only keep those customers where the weather effect is less than 2 standard deviations away from the average weather effect. The weather effect is defined as:

Weather Effect = (Normal Consumption – Actual Consumption) / Actual Consumption

- This basically filters out the outliers – since 96% of all data is within two standard deviations of the mean, this simply eliminates those with abnormally large weather effects.

The final step is to match those customers in the "pre" analysis with those in the "post" analysis

Attachment 71.2.1

SAMPSON
RESEARCH
Consulting

EVALUATION OF TERASEN'S 2005-07 HEATING SYSTEM UPGRADE PROGRAM

FINAL REPORT

Prepared for:

Terasen Gas
Surrey, British Columbia

By:

Sampson Research
&
Habart & Associates

April 7, 2008

1543 Park Avenue
Roberts Creek, BC
V0N 2W2
Phone: 604.740.0254
Email: jsampson@sampsonresearch.com
www.sampsonresearch.com

Disclaimer

The opinions expressed in this report are the responsibility of the author, Sampson Research, and do not necessarily represent the views of Terasen Gas.

Currency Units

All dollar figures presented in this report, unless stated otherwise, are expressed in Canadian funds

Table of Contents

Table of Contents

<u>APPENDICES</u>

List of Exhibits

List of Exhibits

List of Figures

Executive Summary

This report summarizes the findings from the first phase of a two-phase evaluation of Terasen's 2005-07 Heating System Upgrade Program. The program offered a financial incentive of $250 towards the purchase of an Energy Star® qualified high efficiency natural gas furnace or boiler, and an additional $100 incentive if the customer chose a qualifying furnace / boiler equipped with a variable speed drive (VSM) motor. Incentives were in effect from September 2005 to March 2007. The primary objectives of the program were to reduce energy consumption and peak demand associated with the existing residential home heating applications, and to reduce greenhouse gas emissions by increasing the energy efficiency of home heating systems.

Evaluation objectives for the first phase of the two-phase evaluation included:

- Assessing the reasons for program participation, the effectiveness of program marketing / advertising, free ridership, reasons for non-participation, and overall customer and trade ally satisfaction with the program.
- Assessing program impact on sales of qualifying high-efficiency furnaces (HEF), and variable speed blower motors (VSM), for both participating and non-participating customers.
- Documenting and assessing program impact on furnace and secondary heating operating behaviours that affect energy use, with particular emphasis on hours of operation.
- Determining the status of market transformation for high efficiency furnaces, and furnaces with variable speed drive blower motors in the British Columbia market.
- Developing preliminary estimates of program impact on natural gas sales and carbon dioxide emissions.

The objectives of the first phase of the evaluation were addressed using data and information gathered from a combination of program records and primary research with customers and trade allies (furnace dealers and installers). Primary data collection efforts consisted of telephone surveys conducted with representative samples of:

- program participants (n=100);
- non-participants (n=100); and
- furnace dealers, contractors, and installers (n=50).

All surveys were conducted over the telephone during September 2007. Data on program participation, including the preparation of the survey sample frames, was the responsibility of Terasen. Implementation of the surveys was contracted by Sampson Research to Call Us Info Inc.

The second phase of the evaluation (scheduled for autumn 2008) will conduct a billing analysis of participating and non-participating customers to firm up estimates of program savings. This latter phase will commence after study participants have accumulated sufficient billing history (one full heating season) with their new furnace. Phase two will also use data gathered from the market research conducted under phase one of the evaluation.

The conclusions of the study are as follows:

Executive Summary

***Objective 1: Assess the reasons for program participation, the effectiveness of program marketing / advertising, free ridership, reasons for non-participation, and overall customer and trade ally satisfaction with the program*.**

Understanding the importance of Terasen's Heating System Upgrade Program to the decision to install a high efficiency rather than a standard or mid-efficiency furnace is essential to the attribution of energy savings to Terasen's program. In this regard, 57% of participants in the Terasen program credited the program with influencing their decision to purchase a high efficiency furnace, meaning that 43% of participants were free-riders and would have selected a high efficiency furnace without the incentive. The free rider estimate is consistent with the fact that 38% of non-participants that were unaware of the Terasen program installed a high efficiency furnace. Based on information provided by participants, the proportion of free riders for the 2005-07 program is estimated at 43%. This is an increase from 28% estimated for the previous program. The increase is consistent with the continuing transformation of the furnace market to high efficiency units.

Thirty percent (30%) of participants credited the program and its incentives for their decision to replace their furnace, on average, 2.3 years earlier than planned. This is consistent with the significantly higher proportion of participants than non-participants reporting that their old furnace was still operational at the time of replacement (91% versus 71%).

Satisfaction scores assigned to various program attributes by program participants, based on a five-point satisfaction scale, were generally favourable, with the highest score given to application procedures (4.1) and the lowest score given to size of the rebate (3.7). Trade allies also rated the program positively using the same five-point scale with the highest satisfaction score given to the types and number of furnaces eligible for a rebate (4.2), and the lowest score given to the size of the rebate (3.6).

Participants in the program attributed their awareness of the program to an insert in their Terasen bill (29% of participants), heating or furnace contractor (26%), word of mouth (21%), and direct mail from Terasen (15%). Success in program marketing is often reflected in word of mouth traffic. The Terasen program appears to have successfully achieved this result.

More than half (52%) of Terasen's residential customers who replaced their furnaces during the past three years and did not participate in the Terasen program were simply unaware the program existed. The next most common reasons for not participating (mentioned by anywhere from 17% to 19% of non-participants) included the dollar amount of the rebate (i.e., too small), the hassle factor with applying for the rebate, and the fact that the furnace they chose did not qualify. Ten percent (10%) of non-participants indicated they had applied to the program but had their application rejected.

Participants in Terasen's Heating System Upgrade Program are generally very satisfied with their high efficiency furnace. Ten percent (10%) reported experiencing problems with their new furnace, but only 2% reported having major repairs. A large percentage (71%) of participants reported improvements in the comfort of the home after installing their high efficiency furnace. In contrast, 42% of non-participants reported improvements in home comfort after installing their furnace. Customers installing VSM-equipped furnaces were significantly more likely than those installing PSC-equipped furnaces to experience an increase in home comfort (68% versus 43% respectively).

Objective 2: Assess program impact on sales of qualifying high-efficiency furnaces (HEF), and variable speed blower motors (VSM), for both participating and non-participating customers.

Information provided by customers and trade allies during the 2004 and 2007 furnace evaluations confirms that the replacement furnace market in British Columbia is moving towards high efficiency furnaces. Trade allies reported that high efficiency furnaces represented 48% of all replacement furnace sales prior to the launch of the most recent program. This share rose to 65% during the program and then declined to 56% after rebates ended in March 2007. VSM-equipped furnaces (either mid- or high efficiency) accounted for 34% of all furnace sales prior to program launch, and 44% following the program conclusion. Trade allies reported the share rising to 56% while the program was in operation.

Forty-three percent (43%) of non-participants reported installing high efficiency furnaces, while 39% installed standard or mid-efficiency furnaces. The remaining 13% of non-participants were not sure of their furnaces' efficiency. The decision not to install a high efficiency model was influenced by first cost, length of payback period, and a general lack of awareness of the relative costs and benefits of high efficiency furnaces. Non-participants were more likely than participants to have annual household incomes of less than $40,000, meaning that the relatively higher cost of a high efficiency furnace (approximately $700 more than a mid-efficiency furnace) was more of a financial hurtle for these households.

The top three reasons for installing a furnace equipped with a variable speed motor were the desire to save electricity (mentioned by 42% of participants), the contractor's recommendation (35%), and the $100 incentive offered by Terasen and its partners (11%). Trade allies were somewhat less likely than customers to attribute the decision to purchase a VSM-equipped furnace to the influence of the rebate (53% versus 57%). The customer-based estimate of free riders was used in the analysis of program impact.

Objective 3: Document and assess program impact on furnace and secondary heating operating behaviours that affect energy use, with particular emphasis on hours of operation.

Four factors influencing furnace operating costs (and savings) were explored in this evaluation – changes in furnace fan operating behaviours, changes in thermostat setting, changes in operating settings, and changes in supplementary heating.

How homeowners use their furnace to heat or cool the house, or to provide ventilation either occasionally or continuously before and after the installation of a VSM-equipped furnace affects the amount of electricity savings realized from the VSM blower motor. The economics of VSM furnace fans depend on operating hours – low operating hours significantly increases the payback period for VSM-equipped furnaces.

This evaluation found that, regardless of the furnace blower type, the number of households using their furnaces to intermittently heat or cool their homes during the heating/cooling seasons declined after installing their new furnace, and a proportion increased their use of the fans to provide continuous heat or cooling during the heating / cooling seasons. The data is inconclusive as to the influence of blower motor choice on behaviours as a significant proportion of households installing furnaces equipped with PSC motors also changed their usage to one of providing more continuous heat or cooling, or to provide ventilation for part of the year . Households that installed VSM-equipped furnaces, however, were more likely to use their fans continuously.

Executive Summary

The evaluation found that households who replaced their old PSC-equipped furnaces with a VSM-equipped furnace are comprised of several user types – with no conclusive evidence to suggest that households that used their old furnaces either continuously for heating/ cooling, continuously, or to provide ventilation were predisposed to purchase a VSM-equipped furnace. Instead, energy efficiency, the recommendation of the contractor, and non-energy benefits (e.g., improved comfort, improved air quality via air circulation, pollen filters, etc.) appear to have been more important considerations. Interestingly enough, some households purchasing VSM-equipped furnaces appear to have had unrealistic expectations regarding the electricity savings potential of VSM blowers, as they rated their satisfaction with electricity bill savings from their VSM-equipped furnaces significantly lower than households who purchased PSC-equipped furnaces (3.8 versus 4.2 using a five-point satisfaction scale). Data on furnace fan operating behaviours prior to furnace change out suggest that a significant number of households installing VSM-equipped furnaces tended to use their old furnace fans only intermittently, implying their electricity bill savings would be less significant that those who operated the fans more frequently or continuously.

Changes to Furnace Thermostat Setting

Only 4% of participants and 11% of non-participants increased their thermostat setting to keep their house warmer since installing their new furnace. A significantly greater proportion of participants than non-participants reported turning down the thermostat since replacing their furnace (22% versus 9%). When increases or decreases in temperature (in degrees Celsius) are added to those who reported no change, the net change in indoor temperature for participants was minus 0.6 degrees Celsius compared to plus 0.4 degrees for non-participants. This suggests that participants are maintaining their home temperatures a full degree lower than non-participants, effectively adding to the energy savings attributable to participation in the Terasen program.

Changes to Furnace Operating Settings

Only 5% of participants and 1% of non-participants reported changing one or more operating settings. Participants mentioned changing the furnace to run less frequently, resetting the blower, installing a digital readout, and installing air conditioning. The non-participant reported adjusting the timing of the second stage burner so that it engaged sooner.

Changes to Supplementary Heating

The evaluation found that participants were significantly more likely than non-participants to reduce their use of supplemental heating after replacing their furnace (-16% versus -2%). This suggests that participants' new furnaces are picking up some of the heating load previously met through supplemental sources, most notably the natural gas fireplaces, and to a lesser degree, electric heaters. The transfer of the heating load to the new furnace may result in additional savings as the furnace will be more efficient than the natural gas fireplace. However this may be partially offset if supplementary heating in the pre-furnace change-out period was being used to improve the comfort in the home or parts of the home (e.g., temperature variations between rooms, temperature fluctuations between furnace cycles, etc.). The forthcoming refinement of program savings using a billing analysis will, by its nature, capture these changes in supplementary heating use and the net impact of other changes in heating/cooling use.

Objective 4: Determine the status of market transformation for high efficiency furnaces, and furnaces with variable speed drive blower motors in the British Columbia market.

Market transformation is measured, in part, by changes in market shares of high efficiency products, and declines in the relative price differential of high efficiency units relative to standard efficiency units.

High efficiency furnaces' share of the replacement furnace market rose from 48% prior to program launch to 65% during the program phase, before retreating to 56% after the conclusion of the program. A review of market share data from the past and present evaluations suggests a moderate pullback in the market when no program is in place.

Trade allies reported that 54% of all furnaces replaced between September 2005 and March 2007 were eligible for a rebate from Terasen Gas or its partners.

Trade allies reported that the share of the replacement furnace market represented by VSM-equipped furnaces increased from 34% in the pre-program period to 56% during the program, and then falling to 44% in the post-program period. Terasen's program records indicate that 65% of participants in the heating upgrade program installed a high efficiency furnace equipped with a VSM blower motor. A review of historical market share data suggests that like high efficiency furnaces, VSM market shares seesaw when programs are in effect versus when they are not, although the general trend is upward.

A comparison of equipment and installation costs provided by trade allies surveyed in 2003 and 2007 suggests that equipment prices for all furnace models regardless of efficiency increased over the four-year period, while installation costs either stayed the same or declined somewhat. High efficiency furnaces still cost more on an installed basis than mid- or standard efficiency units. The incremental cost of installing a 75,000 BTU/hour high efficiency furnace compared to a 90,000 BTU/hour mid-efficiency furnace (comparable in output based on efficiency) is $696, down from $877 in 2002, but up somewhat from $608 in 2003.

Objective 5: Develop preliminary estimates of program impact on natural gas sales and carbon dioxide emissions.

Energy savings attributable to Terasen's 2005-07 residential Heating System Upgrade Program, using a net to gross ratio 0.57, include 66.1 terajoules (TJ) in annual savings, plus an additional 22.6 TJ of savings for the first 2.3 years (spillover). Estimated peak day savings are 0.48430 TJ for the first 2.3 years, and then 0.36091 TJ for the remaining years. Assuming an emissions factor of 50 tonnes carbon dioxide per terajoule of energy saved, Terasen is credited with reducing CO^2 emissions from residential furnaces by 4.435 kilotonnes in the first 2.3 years, and 3.305 kilotonnes for subsequent years.

1 Introduction & Objectives

This report presents the results of the first phase of a two-phase evaluation of Terasen's 2005-07 Heating System Upgrade Program. The program offered a financial incentive of $250 towards the purchase of an Energy Star® qualified high efficiency natural gas furnace or boiler, and an additional $100 incentive if the customer chose a qualifying furnace / boiler equipped with a variable speed drive (VSM) motor. Incentives were in effect from September 2005 to March 2007. The primary objectives of the program were to reduce energy consumption and peak demand associated with the existing residential home heating applications, and to reduce greenhouse gas emissions by increasing the energy efficiency of home heating systems.

Evaluation objectives for the first phase of the two-phase evaluation included:

- Assessing the reasons for program participation, the effectiveness of program marketing / advertising, free ridership, reasons for non-participation, and overall customer and trade ally satisfaction with the program.
- Assessing program impact on sales of qualifying high-efficiency furnaces (HEF), and variable speed blower motors (VSM), for both participating and non-participating customers.
- Documenting and assessing program impact on furnace and secondary heating operating behaviours that affect energy use, with particular emphasis on hours of operation.
- Determining the status of market transformation for high efficiency furnaces, and furnaces with variable speed drive blower motors in the British Columbia market.
- Developing preliminary estimates of program impact on natural gas sales and carbon dioxide emissions.

The second phase of the evaluation (scheduled for autumn 2008) is to conduct a billing analysis of participating and non-participating customers to firm up estimates of program savings. This latter phase will commence once study participants have accumulated sufficient billing history (one full heating season) with their new furnace. Phase two will also use data gathered from the market research conducted under phase one of the evaluation.

The objectives of the first phase of the evaluation were addressed using data and information gathered from a combination of program records and primary research with customers and trade allies (furnace dealers and installers). Primary data collection efforts consisted of telephone surveys conducted with representative samples of:

- program participants (n=100);
- non-participants (n=100); and
- furnace dealers, contractors, and installers (n=50).

All surveys were conducted over the telephone during September 2007. Data on program participation, including the preparation of the survey sample frames, was the responsibility of Terasen. Implementation of the surveys was contracted by Sampson Research to Call Us Info Inc.

Introduction & Objectives

1.1 Report Organization

The main body of this report is organized into six sections. Following the introduction, Section 2 provides an overview of high efficiency furnace design and characteristics, an overview of the Terasen Heating System Upgrade Program, and a discussion of issues, data sources, and methodologies used in the evaluation. Section 3 summarizes the findings from the telephone survey of participating and non-participating customers. The results from the survey of furnace dealers and contractors (trade ally survey) are summarized in Section 4. The analysis of the program's impact on customer behaviours, the replacement furnace market in Britsh Columbia, and energy and carbon dioxide emissions is presented in Section 5. Summary and conclusions are presented in Section 6. A bibliography of publications referenced in the report is found immediately after Section 6.

This report is accompanied by three appendices. Appendix A includes the participant and non-participant survey questionnaires. Appendix B includes the trade ally survey questionnaire, the steps and analysis undertaken by Terasen staff to prepare the samples of participants, non-participants, and trade allies for use in the surveys are documented in Appendix C. Appendix D presents expanded tabulations for select questions from the customer and trade ally surveys.

2 Background & Methodology

2.1 Furnace Efficiency

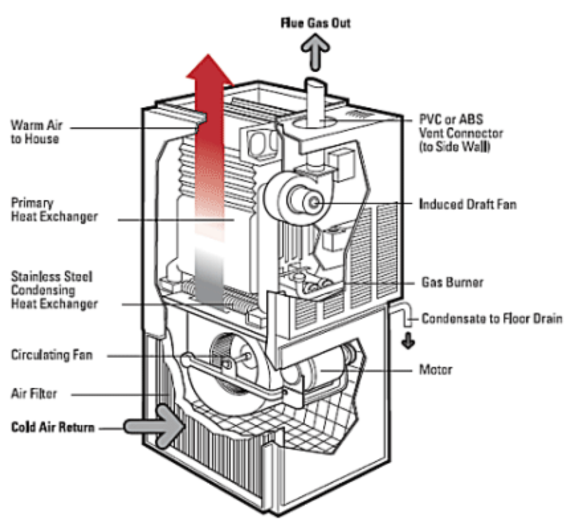
The efficiency of home heating systems is measured by the annual fuel utilization efficiency (AFUE) rating. The AFUE rating is the ratio of the heat output to the total energy consumed by the furnace. An AFUE rating of 90%, for example, tells homeowners that every dollar spent on energy will deliver 90 cents of heat output. Based on their efficiency rating, furnaces are typically grouped into one of three possible efficiency classes: standard efficiency, mid-efficiency, or high efficiency. High efficiency furnaces are also known as condensing furnaces.

Standard efficiency furnaces have a seasonal AFUE of 60% to 70% and typically use a standing pilot light, a single stage heat exchanger (captures heat from the combustion of the natural gas), and draw air for combustion from inside the house. These furnaces require a chimney to expelled combustion gases to the outside of the house.

Mid-efficiency furnaces have a seasonal AFUE of 78% to 84%, use electronic ignition, a draft hood, and incorporate a power controlled vent fan to reduce indoor air lost up the chimney. This is the base level of efficiency available for sale in Canada.

High efficiency or condensing furnaces represent the most efficient furnaces available with an AFUE of 90% to 97%. They are characterized by electronic ignition and a secondary heat exchanger that recovers 10 to 17% more of the heat given off by combustion. Some draw air for combustion from a pipe to the outside of the house. The heat extracted from the combustion gases causes the gases to cool to the point that they condense (turn to water). The remaining gases are cool enough to be vented to the outside by way of a PVC or ABS pipe. The condensate (water) empties to a floor drain. A cutaway schematic of a high efficiency furnace is presented in Exhibit 1.

Exhibit 1: Cutaway Schematic of a Typical High Efficiency Condensing Furnace



Source: "Choose the Right Condensing Gas Furnace" fact sheet published by Natural Resources Canada, http://oee.nrcan.gc.ca/publications/infosource/pub/gas-furnace-2007/index.cfm

2.2 Energy Star®

Terasen's Heating System Upgrade Program required that all furnaces eligible for a rebate be Energy Star® qualified. Energy Star gas furnaces and boilers represent the most fuel efficient units in their class, having met the efficiency and quality criteria set by the Energy Star program. Energy Star qualified furnaces display the Energy Star symbol (Exhibit 2) on the furnace, on the packaging, or in promotional or educational literature. Currently, Energy Star qualified gas furnaces have an annual fuel utilization efficiency (AFUE) rating of 90% or more. Most leading manufacturers of home heating and cooling equipment are producing high-efficiency systems that qualify for Energy Star certification.

Exhibit 2: Energy Star Label

2.3 Furnace Fans

Furnace blowers (fans) are operated by either a Permanent Split Capacity (PSC) motor or the more energy-efficient Electronically Commutated Permanent Magnet (ECPM or ECM), also commonly referred to as a Variable Speed Motor (VSM). PSC motors can be set up to operate at any one of up to four speeds to match the needs of the installation, with maximum efficiency achieved at their highest speed. When operated at lower speeds, the efficiency of a PSC motor quickly drops off. VSMs, by comparison, operate through a range of speeds, with their efficiency maintained by electronics. They use less energy than PSC motors throughout their operating range – with estimates ranging from 20% to 50% less depending upon how the homeowers use their furnace fans. In addition to their higher efficiency, VSMs typically last longer and run quieter.

Some furnace blowers are run continuously at a low speed during the heating season to improve home comfort. Some homeowners install central air-conditioning systems that utilize the same furnace blower. Both practices dramatically increase annual electrical consumption by the furnace, compared with the traditional demand-only mode of operation during the heating season. The electricity savings achieved from switching from a PSC-equipped furnace to a VSM- equipped furnace are maximized if the furnace fan is typically operated in either continuous mode or to provide ventilation in addition to intermittent heating.

Some of the gas savings from a furnace equipped with a VSM motor will be offset by the need for the furnace to supply heat traditionally given off by the lesser efficient PSC motor. However, when central air conditioning is used, VSM blower motors will provide additional savings since they give off less heat than a PSC motor.

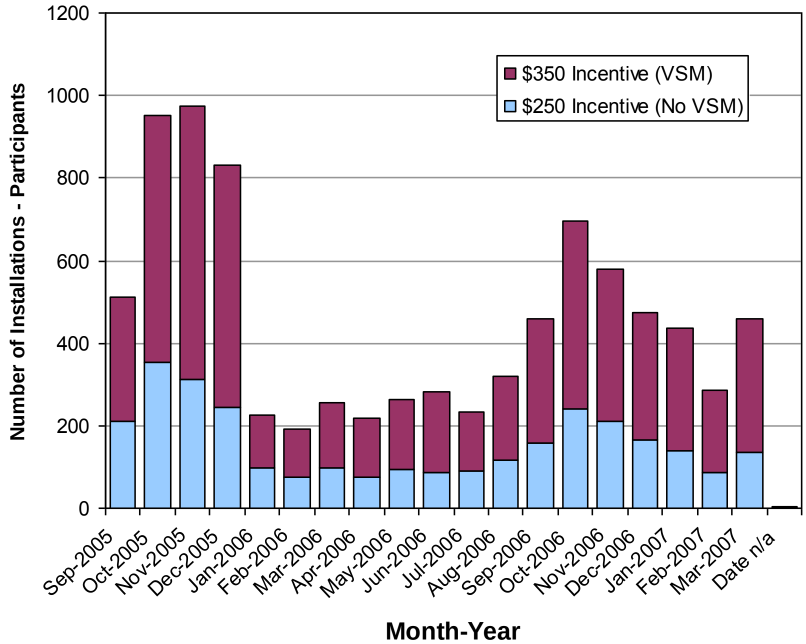
2.4 Program Description and Statistics

Terasen's 2005-07 Heating System Upgrade Program offered a financial incentive of $250 towards the purchase of an Energy Star® qualified high efficiency natural gas furnace or boiler, and an additional $100 incentive if the qualifying furnace / boiler was equipped with a variable speed drive motor

(VSM). Incentives were offered from September 2005 to March 2007. The $250 incentive was funded by Terasen and the British Columbia Ministry of Energy Mines and Petroleum Resources. The VSM incentive was funded by Terasen, Natural Resources Canada (co-funding ceased March 2006), BC Hydro (BC Hydro customers only), and Fortis BC (Fortis BC customers only). The primary objectives of the Heating System Upgrade Program were to reduce the energy consumption and peak demand associated with the existing residential home heating applications, and to reduce harmful greenhouse gas emissions by increasing the energy efficiency of home heating systems. The economic effectiveness of the program depends upon the marginal cost of energy conserved being less than the marginal cost of new supply.

In total, 8,652 households participated in the initiative, with 65% or 5,667 households opting to install a high efficiency furnace equipped with a VSM blower motor. Figure 1 illustrates the monthly program activity in terms of the number of installations per month.

Figure 1: Terasen Heating System Upgrade Program – Installations by Month-Year



2.5 Evaluation Issues, Data Sources, and Methods

The evaluation of the 2005-07 Heating System Upgrade program is being conducted in two phases. The first phase addressed factors influencing program participation, free riders, program-induced changes to furnace and furnace blower operating behaviours, customer and trade ally satisfaction, and preliminary estimates of program savings and reductions in carbon dioxide emissions. The second phase of the evaluation will undertake a billing analysis of participating and non-participating customers to firm up estimates of program savings. This latter phase will commence after study participants have accumulated sufficient billing history (one full heating season) with their new furnace. The phase two evaluation will also use data gathered from the market research conducted under the first phase of the evaluation plan.

Exhibit 3 lists the evaluation objectives for the first and second phases of the evaluation, and identifies the data sources and methods used to satisfy each. Primary data and information for phase one came from telephone surveys conducted with representative samples of program participants (n=100), non-participants (i.e., customer who replaced a furnace but did not participate in Terasen's furnace program) (n=100), and trade allies (i.e., furnace dealers and contractors) (n=50). The surveys were used to estimate a wide range of variables pertaining to program awareness; satisfaction; characteristics of customers, trade allies, furnaces, housing, and the market; furnace prices; and free rider and spillover effects. Each of these estimates have a different level of confidence due to variations in the size of their respective standard errors.

Exhibit 3: Evaluation Issues, Data Sources and Methods

Evaluation Issue	Data Sources	Methods
Phase 1.		
Assess the reasons for program participation, the effectiveness of program marketing / advertising, barriers to participation, and overall customer and trade ally satisfaction with the program.	Participant survey Trade ally survey	Cross tabulations
Assess program impact on sales of qualifying high-efficiency furnaces, and variable speed blower motors (VSM), for both participating and non-participating customers.	Participant survey Non-participant survey Trade ally survey	Cross tabulations
Document and assess program impact on furnace and secondary heating operating behaviours that affect energy use, with particular emphasis on hours of operation.	Participant survey Non-participant survey	Cross tabulations
Determine the status of market transformation for HEFs, and VSMs, in the British Columbia market.	Participant survey Non-participant survey Trade ally survey	Cross tabulations
Develop preliminary estimates of program impact on natural gas sales and carbon dioxide emissions.	Program records Previous research Participant survey	Engineering algorithm Previous billing analysis
Phase 2.		
Determine program impact on natural gas consumption using weather-adjusted billing data	Customer survey Billing records Weather files	Weather-adjusted billing analysis
Calculate estimates of program impact	Billing analysis Customer survey	Engineering algorithm
Determine program impact on carbon dioxide reductions	Billing analysis Terasen assumptions	Engineering algorithm

The participant survey sample was developed using program records. Non-participants were drawn from Terasen's general billing database. Non-participants were eligible to complete a survey if they had replaced their furnace during 2005, 2006, or the first three months of 2007. The survey of trade allies used information on registered contractors that participated in the program. Appendix C provides details on the steps undertaken to prepare the survey samples for each of the three surveys.

2.5.1 Survey Results

The participant (n=100) and non-participant surveys (n=100) were conducted between September 6 to 23, 2007. Results for proportion-based questions are accurate to plus or minus 9.8%, 19 times out of 20.

The trade ally survey (n=50) was conducted between September 10 to 15, 2007. Applying a finite population correction factor, questions yielding sample proportions are accurate within plus or minus 13.3%, 19 times out of 20.

2.6 Phase One Impact Formulae

Analysis of Terasen's impact on high-efficiency furnace sales is based on the following equation (1), where the number of units rebated was obtained from program information and the free rider rate was derived using participant survey information.

(1) Net furnace sales due to program = Units rebated $*$ (1 – free rider rate)

Analysis of program impact on sales of variable speed blower motors (VSM) was calculated using equation (2), where units rebated came from program information and free rider rate is derived from the participant survey.

(2) Net VSM sales due to program = Units rebated $*$ (1 – free rider rate)

Determination of annual energy savings due to the program considered two actions that were taken in response to the incentive: installation of a high-efficiency furnace rather than a standard efficiency furnace, and early replacement of a furnace (spillover).

Determination of program savings, exclusive of any spillover, is determined by equation (3), where units rebated comes from program information and the free rider rate was based on consumer survey information.

(3) Direct Energy Savings = $C_{RF} * (AFUE_{rep} / AFUE_{leg} - AFUE_{rep} / AFUE_{prgm}) * (1 - FR) * Units$

C_{RF}	- Annual consumption of replaced furnace
$AFUE_{rep}$	- AFUE of replaced furnaces
$AFUE_{leg}$	- Current legislated minimum AFUE for furnaces sold in British Columbia
$AFUE_{prgm}$	- Average AFUE of furnaces rebated by Terasen
FR	- Free riders (proportion of gross participants)
Units	- Number of units rebated

Equation (3) explicitly accounts for the fact that the least efficient furnace available on the market today, has, by law, an AFUE (78%) that is higher than the AFUE of the typical furnace being replaced (~70% to 71%). This means that even without Terasen's program, the vast majority of households replacing their old furnaces would have no choice but to purchase a unit with an AFUE higher than their old furnace. Without this adjustment, energy savings from this incremental improvement in furnace efficiency would be incorrectly attributed to Terasen's Heating System Upgrade Program.

Equation (4) details the determination of spillover (SO) savings based upon information regarding attribution and years of advancement provided from the customer survey.

(4) Spillover Energy Savings = $C_{RF} * (1 - AFUE_{rep} / AFUE_{leg}) * Units * Years\ Advanced$

C_{RF}	- Annual consumption of replaced furnace
$AFUE_{rep}$	- AFUE of replaced furnaces
$AFUE_{leg}$	- Current legislated minimum AFUE for furnaces sold in British Columbia
Years	- Number of years early replacement
Units	- Number of units rebated

Spillover savings are calculated to estimate the additional natural gas that would have been consumed had the conventional furnace been used for the "years advanced" period. They are based on the difference in consumption between the conventional furnace and the legislated level, as the reduction between the legislated level and the high efficiency furnace is captured in Equation (3) above.

Calculating the reduction in carbon dioxide (CO^2) emissions from the energy saved by the program is achieved using equation (5), with the emissions factor supplied by Terasen.

(5) ΔCO_2 = (Direct Energy Savings + Spillover Energy Savings) x EF

ΔCO_2 - Change in CO^2 emissions in tonnes
EF - Emissions factor (tonnes CO^2 per GJ energy)

2.7 Phase Two Billing Analysis

Estimated monthly consumption by calendar month for participants and non-participants will be provided by Terasen. Post-program consumption information will be weather normalized using information on heating degree-days from a suitable regional weather station. This weather normalized data will be augmented with pre-installation weather normalized data. An initial estimate of the difference in pre/post consumption due to the program will be estimated as follows in equation (6).

(6) Change in consumption in gigajoules = change in participant consumption – change in non-participant consumption

Analysis of carbon dioxide emissions is based on the following equation (7) where the emissions factor is provided by Terasen.

(7) Change in carbon dioxide emissions in tonnes = number of participants x b $*$ emissions factor/1000 tonnes

3 Customer Survey Results

The participant (n=100) and non-participant surveys (n=100) were conducted between September 6 to 23, 2007. Results for a typical proportion-style question are accurate within plus or minus 9.8%, 19 times out of 20.

3.1 Customer Characteristics

A series of questions were asked of all survey respondents to understand the demographic make-up of participants and non-participants, and to identify any characteristics that distinguished the two groups of customers from one another other than participation or non-participation in Terasen's Heating System Upgrade Program.

Exhibit 4 summarizes the age profile of participants and non-participants. Compared to participants, non-participants tended to have proportionately fewer homeowners who were in the middle age group (35 to 55 years) and relatively more homeowners aged 55 years of age and older (63%). Indeed, 41% of non-participants were 65 years of age or older, compared to 28% of participants.

Exhibit 4: Age of Respondents

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Less than 19 years	-	-	-
19 to 24 years	1%	1%	1%
25 to 34 years	4%	2%	5%
35 to 44 years	12%	13%	11%
45 to 54 years	22%	26%	17%
55 to 64 years	24%	26%	22%
65 years and older	35%	28%	41%
DK/NR	4%	4%	3%
Total	100%	100%	100%
Summary			
34 years and younger	*5%*	*3%*	*6%*
35 to 54 years	*34%*	*39%*	*28%*
55 years and older	*59%*	*54%*	*63%*

Totals may not sum due to rounding
DK/NR = Don't know / no response

The participants were more likely than non-participants to be married or in common-law relationships (81% versus 71% respectively) (Exhibit 5). Non-participants were more likely to be single or widowed, an outcome consistent with the higher proportion of young adults and seniors in this group.

Exhibit 5: Marital Status of Respondents

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Single	10%	6%	13%
Married/Common-Law	76%	81%	71%
Divorced/Separated	3%	4%	1%
Widowed	7%	4%	9%
DK/NR	6%	5%	6%
Total	100%	100%	100%

Totals may not sum due to rounding

Participants and non-participant households had an average of 2.7 and 2.8 individuals living at home. The age profiles of household members are presented in Exhibit 6.

Exhibit 6: People in the Household by Age Group

	Total	Participants	Non-Participants
Base (n),***	*175 - 185*	*90 - 94*	*85 - 91*
Less than 19 years	4%	3%	4%
19 to 24 years	35%	32%	38%
25 to 34 years	18%	23%	13%
35 to 44 years	15%	15%	15%
45 to 54 years	20%	15%	25%
55 to 64 years	3%	4%	2%
65 years and older	5%	8%	3%
Total	100%	100%	100%
Average per Household	*2.8*	*2.7*	*2.8*

Totals may not sum due to rounding
** excluding DK/NR*
*** The number of household members by each age category were queried individually. Consequently, the number of DK/NR responses sometimes differed by age group. This, in turn, affected the base (n) counts after removing DK/NR responses.*

The education profile of survey respondents is presented in Exhibit 7. It shows that participants in Terasen's 2005-07 Heating System Upgrade Program are more likely than non-participants to have taken some form of post-secondary education (73% versus 66%).

Exhibit 7: Educational Status of Survey Respondents – Highest Level of Schooling Attained

	Total	Participants	Non-Participants
*Base (n)**	*175*	*90*	*85*
Some high school	7%	6%	9%
Completed high school	23%	21%	25%
Some university/college	13%	11%	14%
Completed university/college	36%	39%	33%
Some trade/technical school	4%	7%	1%
Completed trade/technical school	9%	6%	12%
Post graduate	9%	11%	6%
Total	100%	100%	100%
Summary			
High school or less	30%	27%	34%
Post-secondary	70%	73%	66%

Totals may not sum due to rounding
** excluding DK/NR*

Exhibit 8 presents the income profiles of participant households versus non-participant households rebased to exclude respondents who did not know or declined to answer the question. Consistent with differences observed in the education profile of participants versus non-participants, more than half of all participants (52%) earned more than $80,000 in 2006 compared to less than one third (30%) of all non-participants. On the other end of the income spectrum, non-participants were more likely to earn less than $40,000 a year than participants (30% versus 16%). These results are also consistent with the age profiles of the two respondent groups, with seniors more likely to be living on fixed incomes.

Exhibit 8: Household Income before Taxes

	Total	Participants	Non-Participants
*Base (n)**	*110*	*64*	*46*
Less than $20,000	5%	3%	7%
$20,000 to $39,999	17%	13%	24%
$40,000 to $59,999	24%	20%	28%
$60,000 to $79,999	12%	13%	11%
$80,000 to $99,999	17%	19%	15%
$100,000 to $124,999	12%	13%	11%
Over $125,000	14%	20%	4%
Total	100%	100%	100%
Summary			
Less than $40,000	22%	16%	30%
$40,000 to $79,999	35%	33%	39%
More than $80,000	43%	52%	30%

Totals may not sum due to rounding
** excludes DK/NR*

3.2 Furnace Characteristics

3.2.1 New Furnace

All survey respondents were read descriptions of high efficiency and standard efficiency furnaces, and then were asked to describe the efficiency level of their new furnace. If participants indicated something other than high efficiency, the descriptions were repeated and the question asked again.[1,2] Exhibit 9 shows that despite the effort to clearly communicate the differences between standard and high efficiency furnaces, a small proportion of program participants (6%) still believed they installed a standard efficiency furnace.

Exhibit 9: Efficiency Level of the New Furnace

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Standard Efficiency	23%	6%	39%
High Efficiency	71%	93%	48%
DK/NR	7%	1%	13%

Forty-eight percent (48%) of non-participants indicated their new furnace was a high efficiency model, and 39% indicated their furnace was a standard efficiency model. The higher proportion of non-participants versus participants who were unsure of the efficiency of their new furnace (13% versus 1%) suggests that participation in Terasen's program helped educate the consumer on furnace efficiency. The difficulty some respondents, particularly non-participants, had in identifying the efficiency level of their new furnace, was identified during the previous evaluation (Habart 2004). A review of the data on the efficiency level and age of the replaced furnace (discussed in the upcoming Section 3.2.2) suggests that a small proportion of participants and non-participants also incorrectly identified the efficiency level of their old furnace. Given this, readers should use caution when interpreting analyses using self-reported furnace efficiency data.

Depending upon the treatment of non-participants who were unsure of their new furnace's efficiency, the estimate of baseline market share for high efficiency furnaces can range from 48% to 61%. For example, if "unsure" respondents are assumed to have installed standard efficiency furnaces, the market share of high efficiency furnaces remains at 48%. Conversely, if they are assumed to have installed high efficiency furnaces, then the high efficiency share rises to 61% (48% plus 13%). This assumption, however, is likely optimistic. A conservative approach is to proportion the unknown respondents according to the current breakdown between high and standard efficiency provided by non-participants who knew their furnaces' efficiency (48% + 48%/(39%+48%) * 13%). This approach yields an estimate of high efficiency furnace share among participants of 55%.

Participants and non-participants were asked to identify the size of their new furnace in Btu/hour. As the results presented in Exhibit 10.clearly show, the majority of respondents, regardless of participation, were unable to answer this question. Of the small number that did, participants reported an average furnace size of 64,250 Btu/hour and non-participants reported an average of 72,400 Btu/hour. The small number of responses for each group makes these estimates subject to a large standard error, requiring caution in their interpretation and use.

[1] Only high efficiency furnaces were eligible for a rebate from Terasen.

[2] To avoid adding unnecessary complexity to the customer survey, respondents were not required to differentiate between a standard versus a mid-efficiency furnace. Rather, a standard efficiency furnace was defined in the survey as having an AFUE rating of between 55% to 85%, which, by industry-accepted definitions, includes both standard and mid efficiency furnaces. References to standard efficiency furnaces throughout the customer survey and the analysis of the customer survey results, by default, include both standard and mid efficiency furnaces. The traditional definitions of standard, mid, and high efficiency furnaces were used in the trade ally survey.

Exhibit 10: Capacity of New Furnace (Btu/hour)

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
*Valid (n) ** *	*22**	*12**	*10**
Average	67,955	64,250	72,400
Standard Error	5,361	7,174	8,246
DK/NR	89%	88%	90%

** Caution is advised when comparing responses based on small samples*
*** sample excluding DK/NR responses*

The inability of a large number of respondents to identify the capacity of their new furnace was noted in the evaluation of Terasen's 2003 heating upgrade program (Habart 2004).

All non-participants, and participants that did not receive the $100 VSM incentive were read a description of a variable speed motor and then asked whether their new furnace was equipped with a furnace fan that used a VSM. Exhibit 11 summarizes the findings for participants and non-participants, organized by efficiency level of the furnace. Participants with VSM blowers include all who received the VSM rebate plus those who did not but indicated, through questioning, that they had installed a VSM-equipped furnace.

Exhibit 11: Blower Motor Type by Efficiency of New Furnace
Participants versus Non-Participants

	Participants				Non-Participants			
	Standard Efficiency	High Efficiency	Unknown Efficiency	All Efficiency Levels	Standard Efficiency	High Efficiency	Unknown Efficiency	All Efficiency Levels
Base (n)	*6**	*93*	*1**	*100*	*39*	*48*	*13**	*100*
PSC	17%	9%	-	9%	26%	35%	31%	31%
VSM	83%	82%	-	81%	46%	40%	15%	39%
DK/NR	-	10%	100%	10%	28%	25%	54%	30%
Total	100%	100%	100%	100%	100%	100%	100%	100%

** Caution is advised when comparing responses based on small samples*

In total, 81% of participants surveyed indicated their new furnace is equipped with a VSM. This percentage includes participants who received a $100 VSM incentive (69%) and participants who indicated their new furnace was equipped with a VSM despite not receiving a VSM incentive from Terasen (12%). VSM-equipped furnaces were installed by an estimated 39% of non-participants. Despite providing a description of the two types of furnace blower motors to survey respondents, 10% of participants and 30% of non-participants did not know whether their furnaces were equipped with a PSC or VSM blower motor.

3.2.2 Replaced Furnace

Eighty-eight percent (88%) of participants indicated their old furnace was a standard efficiency unit, 3% said it was a high efficiency unit, and 9% were unsure of the old furnace's efficiency (Exhibit 12). Non-participants reported similar proportions of standard to high efficiency. A significant percentage (17%) of non-participants could not / did not answer the question.

Exhibit 12: Efficiency Level of Old (Replaced) Furnace

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Standard Efficiency	83%	88%	78%
High Efficiency	4%	3%	5%
DK/NR	13%	9%	17%

Survey respondents were asked about the age of the furnace replaced, and whether the furnace was working at the time it was replaced. If households that participated in the Terasen rebate program replaced their furnaces at a younger age, and/or prior to the furnace failing, this would be viewed as an indicator of potential spillover. If so, Terasen could be credited with additional savings arising from the early replacement of less efficient furnaces. Exhibit 13 summarizes the findings from the participant and non-participant surveys.

Exhibit 13: Age and Operational Status of Old Furnace at Time of Replacement

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Age of furnace at time of replacement	24.4	24.1	24.7
Percent of respondents' furnaces that were working at time of replacement	84%	91%	77%

Ninety-one percent (91%) of participants versus 77% of non-participants indicated their furnaces were working prior to replacing them. Participants and non-participants estimated the average age of their replaced furnace at 24.1 years and 24.7 years on average. These two estimates are not statistically different at the 95% confidence interval.

An analysis of the furnace age data and self-reported efficiency level of replaced furnaces suggests that some households have mistakenly identified their old furnace as high efficiency. For example, three participants reported that their new furnace replaced an existing high efficiency furnace. Two of these furnaces were at least 15 years old when replaced (i.e., one was 15 years old and the other was 27 years old). While it is possible that these participants are correct, high efficiency furnaces represented a very small proportion of the market 15 years ago, and they were just entering the market 27 years ago. The third participant did not know the age of the replaced furnace so an assessment of the correctness of their answer on furnace efficiency was not possible. For non-participants, five reported that their old furnace was a high efficiency unit. However, all but two of these furnaces predated the introduction of high efficiency models.

3.3 Customer Awareness

Forty-eight percent (48%) of Terasen customers who installed a new furnace between January 2005 and March 2007, but did not participate in the furnace rebate program (non-participants), were aware of the rebate program (Exhibit 14). The evaluation of the 2003 program found that only 31% of non-participants were aware of the Terasen Heating System Upgrade Program in effect at that time. There was no statistically significant difference between the age groups of non-participants who were aware versus unaware of the program.

Exhibit 14: Awareness of Furnace Rebate Program among Non-Participants by Age

	Aware	Unaware
*Base (n)**	*48*	*46*
34 years and younger	2%	10%
35 to 54 years	33%	24%
55 years and older	65%	65%
Average	48%	52%

** excludes DK/NR*

Those who participated in the Terasen program (participants) identified four primary sources of their awareness of the program: Terasen bill inserts (mentioned by 29% of participants), furnace contractor (26%), word of mouth (21%), and direct mail from Terasen (15%). Exhibit 15 lists all sources of awareness, ranked by most frequently mentioned to least mentioned.

Exhibit 15: Source of Program Awareness – Participants
Percent of Respondents (Multiple Responses Allowed)

	Percent of all Participants
Base (n)	*100*
Insert in Terasen Gas bill	29%
Through heating or furnace contractor	26%
Word of mouth	21%
Direct mail from Terasen Gas	15%
Terasen Gas website	4%
Newspaper or magazine advertisement	3%
Radio advertisement	3%
TV advertisement	3%
Trade shows and consumer events	2%
Other websites	1%

3.4 Customer Satisfaction

Satisfaction with a series of program and furnace attributes was queried.

3.4.1 Satisfaction with Program Attributes

Exhibit 16 summarizes participants' satisfaction with five different attributes of the rebate program using the average ratings based on a five-point scale, where five represented "very satisfied" and one represented "not at all satisfied". The highest mean score (4.1 out of 5.0) was given to the application procedures to obtain the rebate, while the lowest satisfaction rating (3.7) was given for the amount of the rebate. The standard error of the estimate was 0.1, meaning that differences larger than plus or minus 0.2 in the means are significant at the 95% confidence interval. Satisfaction ratings are generally very favourable, with no apparent program miscues on program information, equipment coverage, or participation procedures.

Exhibit 16: Customer Satisfaction with Various Program Components - Participants
Mean scores using a 5-point satisfaction scale

	Mean Score
Base (n)	*100*
Application procedures to obtain the rebate	4.1
Information on the rebate	4.0
Number or type of furnaces eligible for the rebate	3.9
Information about efficient furnaces	3.9
Amount of the rebate	3.7

See Appendix D for additional detail on this table.

The frequency and nature of calls to a customer call centre about a program can be a useful indicator of potential gaps or confusion in program eligibility, application procedures, or processing times. Slightly more than two of every ten program participants (22%) contacted the Terasen Gas Customer Call Centre about the furnace rebate program. Exhibit 17 lists the reasons for the call based on the frequency of mention. Clarifying their eligibility for receiving the rebate was, by a considerable margin, the reason mentioned by 73% of respondents who called the centre. Determining whether their furnace was eligible for the rebate, and understanding the rebate, were mentioned by 18% of all respondents. The proportion of participants calling Terasen's call centre is not considered excessive.

Exhibit 17: Purpose of Participant's Call to Terasen Gas' Customer Call Centre
Percent of Callers (Multiple Responses Allowed)

	Percent of all Callers
Base (n)	*22**
To clarify my eligibility for the incentive	73%
To determine if the furnace was eligible for the rebate(s)	18%
To understand the rebate	18%
DK/NR	5%

** Caution is advised when comparing responses based on small samples*

3.4.2 Satisfaction with Furnace Attributes

Satisfaction with an energy efficiency program can be strongly influenced by customers' satisfaction with the technology or service for which they received an incentive. In the case of Terasen's furnace rebate program, participants were asked to rate their satisfaction with their choice of furnace. Non-participants were also asked the same question to test for differences related to program participation and furnace efficiency levels.

Exhibit 18 summarizes customers' satisfaction with the choice of furnace, delineated by participants versus non-participants, and those who purchased furnaces with PSC motors versus those who purchased furnaces with variable speed motors (VSMs). Note, both participants and non-participants installed VSM-equipped furnaces.

Overall satisfaction with furnace choice among participants is high, with 86% saying they were either extremely or very satisfied with their choice of furnace. Only 3% said they were not very satisfied or not at all satisfied. Expressed as a mean score using a five point scale (where 5 equals "extremely satisfied" and 1 equals "not at all satisfied"), participants gave their furnaces an average satisfaction score of 4.2 out of 5. By comparison, non-participants gave their furnaces a somewhat lower average score of 4.0 out of 5.0, with fewer non-participants assigning the top score (i.e., extremely satisfied) to their furnace choice.

The proportion of homeowners who were very or extremely satisfied with VSM-equipped furnaces (89%) was significantly higher than those who chose PSC-equipped furnaces (75%), with VSM owners giving an average score of 4.2 out of 5.0 versus 3.9 for PSC owners. The higher satisfaction scores given by households with VSM equipped furnaces appears largely attributable to improvements in home comfort (Section 3.4.3).

Exhibit 18: Customer Satisfaction with Their Choice of Furnace

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Extremely Satisfied (5)	29%	38%	20%	15%	36%	23%
Very Satisfied (4)	54%	48%	60%	60%	53%	53%
Somewhat Satisfied (3)	14%	11%	16%	20%	8%	25%
Not Very Satisfied (2)	2%	2%	1%	5%	1%	-
Not at all Satisfied (1)	1%	1%	1%	-	2%	-
DK/NR	1%	0%	2%	-	2%	-
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Extremely or Very Satisfied	83%	86%	80%	75%	89%	76%
Not Very or Not at all Satisfied	3%	3%	2%	5%	3%	0%
Mean	**4.1**	**4.2**	**4.0**	**3.9**	**4.2**	**4.0**

Totals may not sum due to rounding

Exhibit 19 summarizes the mean satisfaction scores assigned to seven different attributes of the new furnace by participants, non-participants, and participants and non-participants combined. Attributes that received the highest rating from participants included reliability (4.7 out of 5.0), ease of installation (4.4), and after sales service (4.2). Non-participants also rated these the highest, with comparable scores, albeit with slight variations. Participants rated their satisfaction somewhat lower than non-participants for natural gas bill savings, the price of the furnace, and electricity bill savings after installing the furnace. These somewhat lower scores for participants may reflect the higher expectation of energy savings associated with the high efficiency furnaces promoted by Terasen and the trade allies.

Of note, respondents with VSM-equipped furnaces (participants and non-participants) gave significantly lower satisfaction scores to the amount of electricity bill savings compared to those who installed PSC-equipped furnaces. The lower score may be indicative of unmet expectations of electricity savings promised in program literature or through contact with trade allies.

Exhibit 19: Customer Satisfaction with Their New Furnace
Mean Scores using a 5-point Satisfaction Scale

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
The reliability of your furnace	4.6	4.7	4.5	4.4	4.7	4.6
Ease of installation of your furnace	4.4	4.4	4.4	4.4	4.4	4.3
After sales service for your furnace	4.2	4.2	4.3	4.2	4.2	4.4
Natural gas consumption of your furnace	4.2	4.1	4.2	4.1	4.1	4.2
Amount of your natural gas bill after installing the furnace	4.0	3.9	4.1	3.8	4.0	4.1
The price of your furnace	3.9	3.9	4.0	3.9	3.9	4.1
Amount of your electricity bill after installing the furnace	3.9	3.9	4.0	4.2	3.8	4.1

See Appendix D for additional detail on this table.

The incidence of problems with new furnaces is relatively low with only 8% of survey respondents indicating they have experienced problems (Exhibit 20). The difference in the proportion of participants experiencing problems versus non-participants is not statistically significant.

Exhibit 20: Incidence of Problems with New Furnace

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Yes	8%	10%	6%	10%	8%	5%
No	91%	90%	92%	90%	91%	93%
DK/NR	1%	0%	2%	0%	1%	3%
Total	100%	100%	100%	100%	100%	100%

Totals may not sum due to rounding

Those who had experienced problems with their new furnace were asked to elaborate on the nature of the problems. Responses are listed in Exhibit 21. Caution is advised in the interpretation of these results because of relatively few responses.

Exhibit 21: Types of Problems Experienced with New Furnace
Percent of Respondents Experiencing Problems (Multiple Responses Allowed)

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*14**	*10**	*4**	*4**	*9**	*2**
Furnace cycles off and on too frequently	36%	30%	50%	50%	33%	-
Furnace has required major repairs	14%	20%	-	-	22%	-
Difficult to maintain the right temperature	29%	20%	50%	50%	22%	-
Furnace is too noisy	29%	20%	50%	25%	22%	100%
Other	14%	20%	-	50%	-	-
DK/NR	1%	0%	2%	0%	1%	3%

** Caution is advised when comparing responses based on small samples*

The relatively small number of issues reported by respondents who installed VSM equipped furnaces suggests that reliability of VSMs has improved over that observed in the previous evaluation (Habart 2004).

3.4.3 House Comfort

Energy-efficient natural gas furnaces are often promoted as improving the comfort of the home. Participants and non-participants were asked whether comfort in the home has increased, decreased or remained the same since the installation of their new furnace. The results are shown in Exhibit 22. Seventy-one percent (71%) of program participants reported that comfort in the home improved after installing their high efficiency furnace, compared to only 42% of non-participants. Non-participants were twice as likely to say their home's comfort remained the same as before the furnace change-out. Homes with VSM-equipped furnaces were significantly more likely than those with PSC-equipped furnaces to experience an increase in home comfort (68% versus 43% respectively). The proportion of survey respondents indicating that comfort had increased after installing their new furnace did not vary significantly by furnace efficiency.

Exhibit 22: Comfort in House after Furnace Replacement

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Increased	57%	71%	42%	43%	68%	38%
Decreased	2%	2%	2%	3%	2%	3%
Stayed the Same	38%	25%	50%	48%	30%	50%
DK/NR	4%	2%	6%	8%	1%	10%
Total	100%	100%	100%	100%	100%	100%

Totals may not sum due to rounding

Homeowners who reported an increase in comfort were asked to elaborate on how comfort had improved. Exhibit 23 provides the responses, ranked by frequency of mention. The most commonly mentioned benefit was that temperatures between rooms in the house were now more even (59% of all respondents whose comfort has increased). Participants were more likely than non-participants to have mentioned this benefit (69% versus 43%), although there was no difference between those with PSC- versus VSM-equipped furnaces. The next two most frequently mentioned benefits included a warmer house (22%), and increased comfort (non-specific answer) (21%).

Exhibit 23: How Comfort Level in the House Increased
Percent of Respondents who Indicated Comfort has Improved (Multiple Responses Allowed)

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*113*	*71*	*42*	*17**	*81*	*15**
More even temperatures between the rooms	59%	69%	43%	65%	65%	20%
House warmer now	22%	27%	14%	24%	22%	20%
House more comfortable	21%	15%	31%	12%	22%	27%
Indoor air quality has improved	13%	17%	7%	6%	16%	7%
Rooms that were previously cold are warmer	13%	14%	12%	6%	16%	7%
Quiet operation of fan / less noise	12%	17%	5%	6%	15%	7%
DK/NR	3%	1%	5%	0%	1%	13%

** Caution is advised when comparing responses based on small samples*

Those reporting that their homes were less comfortable than before the furnace change complained of cool drafts and increased noise level (Exhibit 24). The one complaint about noise level with VSMs may be related to small duct sizing and the VSM attempting to push more air through the duct that it was designed for.

Exhibit 24: How Comfort Level in the House Decreased
Percent of Respondents Indicating Comfort has Decreased (Multiple Responses Allowed)

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*4**	*2**	*2**	*2**	*1**	*1**
Cool drafts	75%	50%	100%	100%	-	100%
Noise level increased	25%	50%	-	-	100%	-

** Caution is advised when comparing responses based on small samples*

3.5 Furnace Operation

Program participants and non-participants were queried as to the use of their furnace fan before and after the installation of their new furnace. How the furnace fan is used affects the cost-effectiveness of furnace model choice, namely the choice of PSC or VSM-equipped high efficiency furnace. A 2004 Energy Centre of Wisconsin study found that VSM-equipped furnaces used about half the electricity of comparable (PSC-equipped) high efficiency furnaces (Pigg 2004). The study also found that electricity savings for VSM-equipped furnaces increased dramatically for households that run their furnace fan all the time, either to improve air circulation or to eliminate room-to-room variations in temperature.

The participant and non-participant surveys queried four primary modes of furnace fan operation:

- **Intermittent Use**– the blower operates only when the furnace or air conditioning is operating for either:
  - Heating
  - Heating and cooling

- **Continuous Use**– the blower operates at low speed through the year, and at higher speeds when delivering heat or cooling.

- **Seasonal Continuous Use** – the blower operates continuously during the heating and/or cooling seasons. Heating period is assumed to be five months. Cooling period is three months.
  - Heating
  - Heating and cooling

- **Intermittent Use Plus Ventilation** – refers to intermittent use for circulation for part of the year.

Survey respondents were read the six behaviours and asked to indicate which best described their use of the furnace fan prior to replacing the furnace. Exhibit 25 summarizes the results for this question.

Exhibit 25: Furnace Fan Behaviour before Furnace Change

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	40	120	40
Intermittently when providing heat	42%	41%	42%	43%	43%	38%
Continuously during the heating season	18%	17%	18%	28%	16%	13%
Intermittently when providing heat or air conditioning	6%	10%	7%	3%	7%	5%
Continuously during the heating / cooling seasons	8%	5%	6%	3%	9%	8%
Intermittently to also provide ventilation for part of the year	3%	4%	5%	3%	3%	0%
Continuously	4%	3%	3%	5%	4%	0%
No furnace fan (boiler)	5%	2%	2%	13%	3%	3%
DK/NR	18%	18%	17%	5%	16%	35%
Total	100%	100%	100%	100%	100%	100%

Totals may not sum due to rounding

Participants and non-participants were remarkably similar in their furnace fan behaviours prior to replacing their old furnace. The largest use of furnace fans for both groups was to provide heat intermittently (41% and 42% respectively), followed by continuous use during the heating season (17% and 18%). Of note, 18% of participants and 17% of non-participants could not, or chose not to, answer this question (DK/NR).

Respondents were next asked to indicate how they operate their furnace fans since installing their new furnace. The results for this question are summarized in Exhibit 26. Providing heat intermittently remains the most common fan behaviour for both participants and non-participants (36% and 31% respectively), followed by continuously during the heating season (12% and 16%). The proportion of participants who were unable or chose not to answer this question increased to 21% from 18% in the earlier question. The proportion of non-participants who were unable or chose not to answer this question was 21%, up from 17% in the earlier question.

Exhibit 26: Furnace Fan Behaviour after Furnace Change

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Intermittently when providing heat	34%	36%	31%	35%	33%	33%
Continuously during the heating season	14%	12%	16%	23%	11%	15%
Intermittently when providing heat or air conditioning	8%	11%	13%	3%	8%	10%
Continuously during the heating / cooling seasons	12%	10%	8%	10%	15%	5%
Intermittently to also provide ventilation for part of the year	5%	8%	5%	5%	6%	3%
Continuously	5%	2%	4%	5%	7%	0%
No furnace fan (boiler)	2%	0%	2%	8%	0%	3%
DK/NR	21%	21%	21%	13%	20%	33%
Total	100%	100%	100%	100%	100%	100%

Totals may not sum due to rounding

Differences in the number of respondents who were unable or chose not to answer questions regarding furnace fan usage before and/or after the furnace change meant that any before and after comparisons are potentially distorted by the lack of an unequal and/or unmatched base of respondents.[3] The datasets were subsequently rebased to include only those respondents who responded to both the before or after questions. Respondents with boilers were also removed from the analysis. Exhibit 27 summarizes the change in percentage shares between the before and after datasets (net change).

Exhibit 27: Net Change in Furnace Fan Behaviour Shares (Percentage Points) Excluding Non-Responses and Respondents with Boilers

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*143*	*74*	*69*	*29**	*91*	*23**
Intermittently when providing heat	-11	-9	-13	-7	-11	-17
Continuously during the heating season	-4	-5	-3	-7	-5	4
Intermittently when providing heat or air conditioning	5	9	0	3	3	13
Continuously during the heating / cooling seasons	7	3	12	10	9	-4
Intermittently to also provide ventilation for part of the year	3	0	6	0	3	4
Continuously	1	3	-1	0	1	0

** Caution is advised when comparing responses based on small samples*

The proportion of participants and non-participants reporting intermittent use of their new furnace to provide heat declined (down by 9 percentage points and 13 percentage points for the two groups respectively). The proportion of participants using their fans intermittently to provide heat or air conditioning increased 9 percentage points suggesting that some chose to add air conditioning when they replaced their furnace.[4] Proportionately more non-participants than participants reported an

[3] Some respondents answered the "before" questions but not the "after" questions, or vice versa.

[4] An increase in the proportion of participants using their fans intermittently when providing heat or air conditioning was noted during the evaluation of Terasen's 2003 heating upgrade program (Habart 2004).

increase in continuous operation during the heating and cooling seasons (+12 percentage points versus +3 percentage points). As well, the proportion of non-participants using their furnace to provide ventilation for part of the year increased. The latter result is consistent with the proportion of non-participants who reported purchasing a furnace with a variable speed motor (39%).

Use of Furnace Fans to Provide Ventilation

Respondents who indicated they operated their fan intermittently to provide ventilation for part of the year were asked to indicate how many months in a given year they operated their fan this way. Unfortunately, there were an insufficient number of responses by both participants (n=2) and non-participants (n=4) in the pre-installation scenario to report results. In the post-installation case, eight non-participants were able to estimate the number of months (4.3 months per year on average). The two participants who ran their furnaces in this manner could not, or chose not to, provide an estimate of the number of months.

Changes to Thermostat Setting

Participants were queried about their thermostat settings pre- and post-installation of their new furnace to understand whether they offset part of their energy savings by keeping the house warmer. If this hypothesis is correct, estimates of energy savings attributable to participants of the Terasen program would be lower than expected.

Exhibit 28 shows that only 4% of participants and 11% of non-participants have adjusted their thermostat to keep their house warmer in the winter months compared to before the furnace change-out. Interestingly, a significantly greater proportion of participants than non-participants reported turning down the thermostat in the winter months since replacing their furnace (22% versus 9%).

Exhibit 28: Change in Thermostat Setting since Furnace Change - Winter Months Only

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Warmer	8%	4%	11%	5%	8%	10%
Cooler	16%	22%	9%	13%	19%	8%
Same	69%	67%	70%	68%	69%	68%
Too soon to know	3%	3%	2%	0%	3%	3%
DK/NR	6%	4%	8%	15%	1%	13%
Total	100%	100%	100%	100%	100%	100%

Totals may not sum due to rounding

Respondents who changed their thermostat setting (either direction) were asked how many degrees warmer or cooler they were keeping their house since the furnace change. The average increase in temperature (in degrees Celsius) and the average decrease in temperature, and those reporting no change (i.e., an average change of 0 degrees Celsius) were first calculated and then weighted to derive a net change in the temperature for participants and non-participants. The relative proportion of respondents that responded to the three response categories, rebased to exclude “too soon to know” and DK/NR responses, were used as the weights. The results are summarized in Exhibit 29.

Exhibit 29: Average Degree (Celsius) Change in Thermostat Setting since Furnace Change Winter Months Only

	Participants			Non-Participants		
	Average Degree Change	Weight	Weighted Degree Change	Average Degree Change	Weight	Weighted Degree Change
Base (n)	*93*	*93*	*93*	*90*	*90*	*90*
Degrees Warmer	4.7	0.04	0.2	5.0	0.12	0.6
Degrees Cooler	-3.3	0.24	-0.8	2.5	0.10	-0.2
No Change	0.0	0.72	0.0	0	0.78	0.0
Net Change	-	-	-0.6	-	-	0.4

Totals and multiplicative results may differ due to rounding

The net change in indoor temperature for participants was minus 0.6 degrees Celsius compared to plus 0.4 degrees for non-participants. In effect, participants are keeping their homes a full degree cooler than their non-participant counterparts.

Other Changes to Furnace Settings

Other than changes to the thermostat setting, survey respondents were asked whether they had changed any of the furnace operating settings since installing the furnace. Only 5% of participants and 1% of non-participants reported changing one or more operating settings (Exhibit 30).

Exhibit 30: Change Any Other Furnace Operating Setting since Furnace Replacement

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Yes	3%	5%	1%	-	4%	3%
No	95%	94%	96%	100%	94%	93%
DK/NR	2%	1%	3%	-	2%	5%
Total	100%	100%	100%	100%	100%	100%

Totals may not sum due to rounding

When asked to elaborate on what settings were changed, participants mentioned changing the furnace to run less frequently, resetting the blower, installing a digital readout, and installing air conditioning. The sole non-participant that answered yes to this question, reported adjusting the timing of the second stage burner so that it engaged sooner.

3.5.1 Factors Influencing Decision to Purchase a VSM Equipped Furnace

Respondents identified as having a VSM-equipped furnace were asked why they chose a model with a VSM blower. Their answers are summarized in Exhibit 31.

Energy efficiency and the contractor's recommendation were mentioned by significantly more respondents than any of the other possible factors (44% and 38% of respondents with VSM-equipped furnaces). Eleven percent (11%) of participants mentioned the $100 rebate as a motivating factor in their decision.

Exhibit 31: Reasons for Choosing a VSM-Equipped Furnace
Percent of Respondents with VSMs – Multiple Responses Allowed

	Total	Participants	Non-Participants
Base (n)	*99*	*71*	*28**
It is more energy-efficient	44%	42%	50%
The contractor recommended it	38%	35%	46%
I was motivated by the $100 rebate	9%	11%	4%
It provides even heat	7%	10%	0%
It can operate through a range of speeds	6%	6%	7%
It is quieter	5%	6%	4%
I wanted to have continuous ventilation	5%	4%	7%
It provides more comfortable ventilation	4%	4%	4%
Part of the better furnace I wanted	3%	4%	0%
It keeps my house warmer	2%	1%	4%
I wanted better indoor air quality	1%	1%	0%
DK/NR	23%	20%	32%

** Caution is advised when comparing responses based on small samples*

Twenty-one percent (21%) of participants in Terasen's furnace rebate program who knew their furnace blower type were aware of variable speed blower motors prior to purchasing their VSM-equipped furnace, and another 12% were considering purchasing a VSM-equipped furnace (Exhibit 32). The 10% of participants and 30% of non-participants who were unsure whether their furnace had a VSM were excluded from this question.

Exhibit 32: Aware of or Considering the Purchase of a Furnace with a VSM Prior to Installing Furnace?
Asked of Respondents Who Knew their Furnace Blower Motor Type

	Total	Participants	Non-Participants
*Base (n)**	*160*	*90*	*70*
Aware of	19%	21%	17%
Considering Purchase	9%	12%	6%
No	64%	60%	70%
DK/NR	7%	7%	7%
Total	100%	100%	100%

Totals may not sum due to rounding
** excludes households who did not know whether their furnace was equipped with a VSM*

Respondents who were aware of or considering purchasing a VSM-equipped furnace were asked to identify the source of their awareness. Participants were more likely to credit Terasen (39% of all responses) and the contractor (29%) as their top two sources of awareness (Exhibit 33). Non-participants were more likely to identify their contractor as the top source (38%), followed by Terasen (19%) and the Internet (19%). Seven percent of participants identified past experience with VSMs (e.g., installed in a previous residence).

Exhibit 33: Source of Awareness of Variable Speed Furnace Motors
Percent of Respondents Aware of VSMs – Multiple Responses Allowed

	Total	Participants	Non-Participants
Base (n)	*46*	*30*	*16**
Contractor	30%	27%	38%
Terasen Gas	30%	37%	19%
BC Hydro	2%	3%	0%
Power Smart	2%	0%	6%
Friend(s)	4%	3%	6%
Internet	9%	3%	19%
Previous experience	4%	7%	-
Read article(s)	2%	3%	-
Researched various sources	4%	7%	-
Through work	4%	3%	6%
Other	2%	-	6%

** Caution is advised when comparing responses based on small samples*

Reasons why participants and non-participants did not select a VSM-equipped furnace are summarized in Exhibit 34. Overwhelmingly, both groups of households were simply unaware of the product (96% of all responses). Only 2% of respondents said they were too expensive.

Exhibit 34: Reasons Why a Furnace with a VSM not Chosen
Respondents Who Installed a PSC Equipped Furnace – Multiple Responses Allowed

	Total	Participants	Non-Participants
Base (n)	*103*	*56*	*51*
Unaware of variable speed motors	96%	96%	96%
Too expensive	2%	-	4%
VSM not an option on the furnace chosen	1%	2%	-
DK/NR	1%	2%	-
Total	100%	100%	100%

Totals may not sum due to rounding

3.6 Program Design

Survey respondents were asked to rate the relative importance of various home heating attributes in their choice of furnace using a five point scale where five meant "very important" and one meant "not at all important". Exhibit 35 summarizes the mean scores for six different attributes. Participants rated energy efficiency as the most important attribute, scoring an average of 4.5 out of 5. Next most important was home comfort (4.3) and operating cost (4.2). Non-participants gave equal scores to energy efficiency, home comfort, and indoor air quality (4.3 for all three). The lower average score assigned to the initial cost of the system by participants (3.8) versus non-participants (4.1) is consistent with the larger proportion of lower income households that make up the non-participant group. First cost (i.e., purchase and installation costs) is a common barrier for lower income households targeted by energy efficiency programming.

Exhibit 35: Attributes that Influenced Choice of Home Heating System (Mean of the 5-point scale)

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Energy efficiency	4.4	4.5	4.3
Comfort in your home	4.3	4.3	4.3
Indoor air quality	4.2	4.1	4.3
Operating cost of the system (ie: fuel cost)	4.2	4.2	4.2
Both initial cost and operating costs	4.1	4.0	4.1
Initial cost of the system	4.0	3.8	4.1

See Appendix D for additional detail on this table.

The proportion of participants in Terasen's rebate program who said they were familiar with the Energy Star label for natural gas furnaces was significantly higher than non-participants (82% versus 54%) (Exhibit 36).

Exhibit 36: Familiar with Energy Star Label for Natural Gas Furnaces?

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Yes	68%	82%	54%
No	28%	17%	38%
DK/NR	5%	1%	8%
Total	100%	100%	100%

Totals may not sum due to rounding

Of those who said they were familiar with Energy Star, significantly more participants than non-participants recalled seeing the Energy Star label on their furnace or furnace brochure (83% versus 44%) (Exhibit 37). This is consistent with the current 90% AFUE threshold for Energy Star qualified furnaces.

Exhibit 37: Recall Energy Star Label on Furnace or Furnace Brochure?

	Total	Participants	Non-Participants
Base (n)	*136*	*82*	*54*
Yes	68%	83%	44%
No	10%	2%	20%
DK/NR	23%	15%	35%
Total	100%	100%	100%

Totals may not sum due to rounding

When asked to rate the importance of Terasen's incentive program including Energy Star qualified furnaces on a five point scale, where five represented "very important" and one represented "not important at all", 89% of program participants aware of the Energy Star label felt it was important (4 or 5 on the five point scale). Alternatively stated, respondents gave a mean importance rating of 4.5 out of 5.0 (Exhibit 38).

Exhibit 38: Importance of Terasen Incentive Program Including Energy Star Products Five Point Scale Where 1 Represents "Not at all Important" and 5 is "Very Important"

	Participants
Base (n)	*82*
Important (4 or 5)	89%
Not Important (1 or 2)	1%
DK/NR	2%
Mean	4.5

3.7 Furnace Prices

Exhibit 39 summarizes the information provided by survey respondents on the installed cost of their new furnace. These figures represent the sum of the cost of the furnace, contractor mark-up, installation charges, and any applicable taxes and permits. The mean installed cost of the new furnace reported by participants was $3,666, 43% higher than the average $2,567 reported by non-participants. The most commonly reported cost among participants was $3,500 (20% of all participant responses excluding DK/NR) versus $3,000 for non-participants (37% of all non-participant responses excluding DK/NR). PSC-equipped furnaces were less expensive than VSM-equipped furnaces ($2,620 versus $3,493 respectively). The average cost of VSM equipped furnaces installed by participants was $3,740 (not shown), significantly higher than the $2,786 average (not shown) paid by non-participants who installed VSM equipped furnaces. This difference may be due to the incidence of mid-efficiency furnaces sold to non-participants, and possible confusion among non-participants regarding the furnace motor type (i.e., confusing a PSC with a VSM). The price premium for VSM-equipped furnaces may also reflect the presence of other features including two stage burners and better heat exchangers.

Exhibit 39: Installed Furnace Prices ($) Including Taxes

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	40	120	40
*Valid (n)**	*139*	*74*	*65*	30**	81	28**
Price Ranges						
$999 or less	6%	4%	8%	3%	5%	11%
$1,000 - $1999	5%	1%	9%	13%	4%	0%
$2,000 - $2,999	20%	11%	31%	27%	12%	36%
$3,000 - $3,999	43%	41%	46%	53%	38%	46%
$4,000 - $4,999	17%	26%	6%	3%	27%	0%
$5,000 and over	9%	18%	0%	0%	14%	7%
Total	100%	100%	100%	100%	100%	100%
Mean Prices						
Mean Prices	*$3,152*	*$3,666*	*$2,567*	$2,620	$3,493	$2,738
Std. Error	$94	$122	$105	$157	$122	$190

** Excludes DK/NR*
*** Caution is advised when comparing responses based on small samples*
Totals may not sum due to rounding

The mean installed cost of furnaces reported by respondents unaware of their furnace blower motor type ($2,738) suggests that the majority of these were likely standard efficiency furnaces. Twenty-six percent (26%) of participants and 35% of non-participants were unable to recall the cost, or chose not to answer the question.

The evaluation of Terasen's 2003 heating upgrade program found that participants paid an average of $3,727. This average cost is not statistically different than the $3,666 recorded in 2007.[5]

Additional detail about installed furnace costs are provided in Exhibit 40. Non-participant costs were delineated by their self-reported furnace efficiency (standard or high efficiency). The average installed cost for high efficiency furnaces purchased by non-participants was $2,665, higher than the average for standard efficiency furnaces ($2,370), but less than the participant average ($3,666). The higher average costs for participant versus non-participant high efficiency furnaces reflects the larger percentage of participant furnaces that were equipped with VSMs (81% versus 40%). The lower average cost for non-participant high efficiency furnaces may also be due to some non-participant households confusing a mid-or standard efficiency furnace for a high efficiency furnace, despite being provided with verbal descriptions of each during the survey. Trade allies reported that the installed cost of high efficiency furnace was approximately $700 more than a standard or mid-efficiency furnace (Section 4.10).

Exhibit 40: Mean Installed Furnace Prices ($) Including Taxes by Efficiency Level

		Participants	Non-Participants		
	Total	High Efficiency	Standard Efficiency	High Efficiency	Unknown Efficiency
Base (n)	*200*	*100*	*48*	*39*	*13**
*Valid (n)***	*139*	*74*	*25*	*34*	*6*
Price Ranges					
$999 or less	6%	4%	20%	0%	0%
$1,000 - $1999	5%	1%	12%	9%	0%
$2,000 - $2,999	20%	11%	24%	35%	33%
$3,000 - $3,999	43%	41%	36%	50%	67%
$4,000 - $4,999	17%	26%	8%	6%	0%
$5,000 and over	9%	18%	20%	0%	0%
Total	100%	100%	12%	9%	0%
Mean Prices					
Mean	*$3,152*	*$3,666*	*$2,370*	*$2,665*	*$2,833*
Std. Error	$94	$122	$206	$124	$223

** Excludes DK/NR*
Totals may not sum due to rounding

3.8 Housing Characteristics

The housing characteristics of participants and non-participants are summarized in the next three exhibits. Exhibit 41 provides a breakdown of survey respondents by dwelling type. The data show that the two groups were similar in their dwelling types.

[5] Based on a 95% confidence level and standard errors of $125 for the 2003 estimate (Habart 2004) and $122 for the 2007 estimate.

Exhibit 41: Dwelling Type

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Single detached	93%	96%	89%
Semi-detached	2%	1%	2%
Apartment/condominium	1%	-	1%
Row/townhouse	2%	1%	2%
Mobile home or other	2%	-	4%
DK/NR	2%	2%	2%
Total	100%	100%	100%

Totals may not sum due to rounding

Exhibit 42 summarizes participant and non-participant dwellings by age. Of note, non-participants were significantly more likely than participants to live in structures built between 26 and 50 years ago. A relatively larger proportion of participants tended to live in homes aged 16 to 25 years.

Exhibit 42: Dwelling Age

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
15 years or younger	12%	14%	10%
16 to 25 years	19%	24%	14%
26 to 50 years	64%	57%	70%
51 to 75 years	9%	11%	7%
76 years or older	4%	6%	3%
DK/NR	4%	2%	5%
Total	100%	100%	100%
Average Age (Years)	*35.6*	*36.1*	*35.1*

Totals may not sum due to rounding

The slightly larger proportion of non-participants living in single detached properties is consistent with the relatively larger heated floor space of non-participants (2,808 square feet) versus participants (2,494 square feet) (Exhibit 43).

Exhibit 43: Dwelling Size
Heated Floor Space in Square Feet

	Total	Participants	Non-Participants
*Base (n)**	*172*	*86*	*86*
Average (Square Feet)	2,651	2,494	2,808

** Excludes outliers and DK/NR*

The incidence of natural gas end use appliances in participant and non-participant homes is summarized in Exhibit 44.

Exhibit 44: Natural Gas End Uses in the Home
Percent of Respondents (Multiple Responses Allowed)

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Water heating	78%	81%	75%
Main space heating	51%	55%	46%
Fireplace insert	39%	41%	37%
Cooking	18%	19%	17%
Barbeque	16%	19%	12%
Secondary space heating	12%	11%	13%
Clothes drying	8%	7%	9%
Hot tub	4%	2%	5%
Patio heater	2%	2%	1%
Indoor pool heating	1%	1%	1%
Outdoor pool heating	1%	1%	-
DK/NR	2%	3%	-

Water heating and main space heating represent the two most common natural gas end-uses in the home. The incidence of natural gas used in main and secondary heating is surprisingly low. It may be that some households, despite having a natural gas fired furnace, use other source of heating as their main source (e.g., wood stove, heat pump, etc.). Some respondents may also have assumed that the interviewer already knew they had a natural gas fired furnace or boiler and, therefore, was asking about end uses other than the furnace or boiler.

3.9 Supplementary Heating

Exploring changes in supplementary heating in participant homes and non-participant homes is important for understanding its possible influence on energy savings attributable to the program. First, households were asked to identify whether they had a source of supplementary heating in the home. If they answered in the affirmative, they were asked to identify the fuel(s) used for the supplementary heating (e.g., electricity, natural gas, etc.), and the method of supplemental heating (e.g., portable electric heater, wood stove, etc.).

Forty-four percent (44%) of respondents affirmed that they had supplementary heating in the home (Exhibit 45). Participants were somewhat more likely than non-participants to have a supplementary heat source (48% versus 40%).

Exhibit 45: Presence of Supplementary Heating

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Yes	44%	48%	40%	50%	42%	45%
No	55%	50%	59%	50%	57%	53%
DK/NR	2%	2%	1%	-	2%	3%
Total	100%	100%	100%	100%	100%	100%

Totals may not sum due to rounding

The next two exhibits summarize the fuel used for supplementary heating and the types of supplemental heating used. An initial review of the datasets revealed some inconsistencies. For example, some respondents indicated they had a wood stove but did not mention wood as a fuel source in the earlier question. A similar issue was identified for electricity (e.g., had an electric space heater or electric baseboard heat but did not identify electricity as a fuel source). In light of this, data for electricity and wood supplemental fuels were recoded. If a respondent indicated they had an electric appliance of any sort (e.g., electric space heater, electric baseboard heaters, etc.) they were assumed to have electricity as a fuel source. A similar procedure was taken for wood stoves. In the end, natural gas was the most frequently mentioned fuel used for supplementary heating (42% of all respondents with supplemental heat), followed by electricity (38%) and wood (27%) (Exhibit 46).

Exhibit 46: Fuel Used for Supplementary Heating
Percent of Respondents with Supplementary Heating - Multiple Responses Allowed

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*88*	*48*	*40*	*20**	*50*	*18**
Natural Gas	42%	44%	40%	40%	40%	50%
Electricity	38%	38%	38%	35%	42%	28%
Wood	27%	29%	25%	35%	26%	22%
Oil	1%	-	3%	-	2%	-
DK/NR	2%	4%	-	-	4%	-

** Caution is advised when comparing responses based on small samples*

Consistent with the fuel sources identified, respondents identified having a fireplace as the most common supplementary heating method (61% of all respondents with supplemental heat) (Exhibit 47). Electric baseboard heating and portable electric heaters were the next two most common methods, capturing 17% and 9% of mentions by respondents respectively.

Exhibit 47: Types of Supplementary Heating
Percent of Respondents with Supplementary Heating - Multiple Responses Allowed

	Total	Participants	Non-Participants
Base (n)	*88*	*48*	*40*
Fireplace	61%	63%	60%
Electric baseboard heaters	17%	13%	23%
Portable electric heaters	9%	10%	8%
Wood stove	6%	8%	3%
Heat pump	2%	2%	3%
Hot water radiant floor heating	2%	2%	3%
Central forced air furnace	1%	-	3%
Other	1%	2%	-
DK/NR	3%	4%	3%

3.10 Free Riders

Free riders are defined as those households that participated in the Terasen Heating System Rebate program, but would have purchased a high efficiency furnace or boiler even if the incentive had not been available. The energy savings attributable to free riders are excluded from the final determination of program effect.

To assess the degree of free riders, participants were asked to rate the importance of the Terasen financial incentive in their decision to purchase a high efficiency furnace or boiler using a scale of one to five where one meant "not at all important" and five meant "very important". The results are summarized in Exhibit 48. To determine the importance of the program, a weighted average of the importance scores was calculated. The weights were selected to give the most weight to those indicating the incentive was very important (weight of 1.0) and the least weight to those who indicated it was not at all important (weight of 0). The weighted average of the importance scores was 0.57, meaning the free rider rate is 43% (calculated as 1 - Weighted Average Score).

Exhibit 48: Calculation of Free Riders – Influence of Overall Incentive on Participants

	Very Important (5)	(4)	(3)	(2)	Not at all Important (1)	DK/NR	Total	Free Rider Rate
Distribution of Responses (n=100)	26%	27%	17%	10%	13%	7%	100%	-
Weight	1	.75	.50	.25	0	0	-	-
Product	0.26	0.20	0.09	0.03	0.00	0.00	0.57	**0.43**

A similar weighting scheme was used with the importance ratings given to the role of the $100 incentive in the choice of a furnace with a variable speed blower motor (Exhibit 49). The free rider rate in this case was 43%, as well.

Exhibit 49: Influence of the VSM Incentive on Participant's Choice of a VSM-equipped Furnace

	Very Important (5)	(4)	(3)	(2)	Not at all Important (1)	DK/NR	Total	Free Rider Rate
Distribution of Responses (n=69)	26%	26%	16%	13%	7%	12%	100%	-
Weight	1	.75	.5	.25	0	0	-	-
Product	0.26	0.20	0.08	0.03	0.00	0.00	0.57	**0.43**

3.11 Spillover

Exhibit 50 summarizes the spillover analysis conducted using participant survey data. Spillover refers to the early replacement of a standard or conventional furnace with an energy-efficient model due the influence of the Terasen heating upgrade program. Thirty percent (30%) of participants credited the Terasen program with advancing their decision to replace their furnace. The average advancement was estimated at 2.3 years.

Exhibit 50: Spillover Analysis - Participants (Multiple Responses Allowed)

	Participants	Average Early Replacement (Years)
Base (n)	*100*	*23**
Yes	30%	2.3
No	67%	-
DK/NR	3%	-
Total (All Participants)	100%	-

** Excludes DK/NR*
Totals may not sum due to rounding

3.12 Barriers to Participation

Non-participants were asked why they did not participate in the Terasen program. Their responses are summarized in Exhibit 51. By far, the single most common reason was a simple lack of awareness of the program (52% of all non-participants). The next most commonly mentioned reasons included not worth the effort / didn't want to bother (19%), rebate was too small (19%), and furnace did not qualify (17%). Ten percent (10%) said they had submitted a rebate application but were rejected.

Exhibit 51: Reasons for Not Participating in Terasen's Heating Upgrade Program Percent of Non-Participants - Multiple Responses Allowed

	Percent of Non-Participants
Base (n)	*100*
Unaware of program	52%
Not worth the effort / Didn't want to bother	19%
Rebate too small	19%
Furnace did not qualify for rebate	17%
Tried to - rebate application was rejected	10%
Didn't know how to apply	8%
Had planned to / didn't get around to it	6%
Contractor was not registered with program	6%
Other	6%
DK/NR	13%

Totals may not sum due to rounding

4 Trade Ally Survey Results

A sample of 50 furnace dealers, contractors, and gas fitters (trade allies) were surveyed between September 10th and 15th, 2007. Trade allies were selected at random from Terasen's list of qualifying furnace contractors. Including a finite population correction factor, questions yielding sample proportions are accurate within plus or minus 13.3%, 19 times out of 20.

4.1 Trade Ally Characteristics

Exhibit 52 presents the distribution of trade ally respondents by the number of employees in their firm. This measure is used as a proxy for firm size. The vast majority (82%) of respondents worked for firms of ten employees or less, with 16% (not shown) of respondents being owner/operators (single person firms).

Exhibit 52: Distribution of Trade Ally Respondents by Firm Size (Number of Employees)

	Percent of Trade Allies
Base (n)	*50*
1 to 2	30%
3 to 5	28%
6 to 10	24%
11 to 15	10%
16 to 20	4%
Over 20	4%
Total	100%
Mean	*6.9*

Totals may not sum due to rounding

Consistent with the significant proportion of single person firms participating in the survey, 26% of respondents categorized themselves as independent heating contractors. Another 18% of trade allies described themselves as furnace dealers and heating contractors. Only 4% of respondents described themselves as gas fitters. Almost half of trade allies (46%) indicated their business was best described by all three categories – dealer, heating contractor, and gas fitter.

Exhibit 53: How Trade Allies Described Their Business

	Percent of Trade Allies
Base (n)	*50*
Furnace Dealer and Heating Contractor	18%
Independent Heating Contractor	26%
Gas fitter	4%
All of the Above	46%
Other	6%
Total	100%

Totals may not sum due to rounding

An analysis of Terasen's program records revealed that 25% of the 665 contractors participating in the program installed 85% of all the rebated furnaces (Exhibit 54). One contractor was responsible for more than 400 installations.

Exhibit 54: Distribution of Trade Allies by the Number of Rebated Furnaces Installed

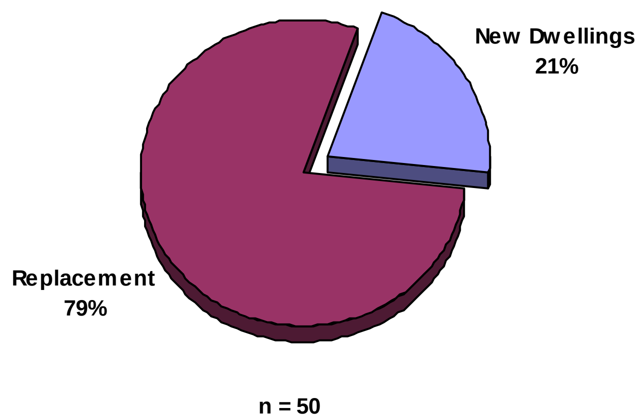
Number of Installations	Percent of All Participating Trade Allies	Percent of All Furnaces Rebated
Base	*665*	*8,652*
1 to 10	15%	75%
11 to 50	31%	18%
51 to 100	28%	5%
101 to 200	21%	2%
> 200	5%	0.2%
Total	100%	100%

Source: Terasen program records

4.2 Market Characteristics

Trade allies estimated that, on average, 79% of their furnace sales / installations were to replace existing furnaces (Figure 2). However this data does not mean that new construction has 21% of the new furnace market. In BC there are a number of firms that only install in new construction, and they are not included in the trade ally survey.

Figure 2: Share of Residential Furnace Sales / Installations: Replacement versus New Dwellings



Trade allies were asked to estimate the percentage of all furnaces sold or installed before, during, and after the Teresan rebate program that were high efficiency. The results, summarized in Exhibit 55, show that the proportion increased from 48% to 65% during the program period before declining to 56% after the end of the program (as indicated in the September 2007 survey).

Exhibit 55: Composition of Replacement Furnace Sales / Installations by Furnace Type Mean Percentages

	Percent High Efficiency	Percent VSM
Base (n)	*50*	*50*
Before Program	48%	34%
During Program	65%	56%
After Program	56%	44%
DK/NR	8%	8%

Trade allies reported that the proportion of furnace sales/installations equipped with variable speed blower motors also increased during the program period, rising from 34% to 56% before declining to 44% as of September 2007.

4.3 Trade Ally Satisfaction

Trade allies were asked to rate their satisfaction with four aspects of Terasen's furnace rebate program using a five point scale, where one represented "not at all satisfied" and five represented "very satisfied". Exhibit 56 summarizes the mean scores. Responses were generally very favourable. The highest satisfaction score was given to the types or numbers of furnaces eligible for the rebate (mean satisfaction score of 4.2). The amount of the rebate received the lowest mean score (3.6).

Exhibit 56: Trade Ally Satisfaction with Various Aspects of the Terasen Rebate Program Mean of the 5-point Satisfaction Scale

	Mean Score
*Base (n)**	*46 - 49*
Types or numbers of furnaces eligible for the rebate	4.2
Application procedures to obtain the rebate	4.1
Information on the rebate	3.8
Amount of the rebate	3.6

** base varies by aspect due to varying numbers of DK/NR responses*
See Appendix D for additional detail on this table.

Fifty-eight percent (58%) of trade allies felt the Terasen rebate was either very or somewhat important in the choice of a high efficiency furnace when asked to rate the importance using a five point scale, where five represented "very important" and one represented "not at all important" (Exhibit 57). Averaged across all valid responses, trade allies gave the rebate a mean score of 3.7 out of 5.0.

Exhibit 57: Importance of the Rebate in Furnace Choice

	Percent of Trade Allies
Base (n)	*50*
Important (4 or 5)	58%
Not Important (1 or 2)	18%
DK/NR	4%
Mean	3.7

Trade allies assigned somewhat less importance to the role of the $100 VSM rebate in their customers' choice of furnace blower motor efficiency (Exhibit 58). Forty-six percent (46%) felt the rebate was either very or somewhat important in the decision to acquire a VSM-equipped furnace. Averaged across all valid responses, trade allies gave the VSM rebate a mean score of 3.2 out of 5.0.

Exhibit 58: Importance of the VSM Rebate in the Choice of a VSM-equipped Furnace

	Percent of Trade Allies
Base (n)	*50*
Important (4 or 5)	46%
Not Important (1 or 2)	34%
DK/NR	2%
Mean	3.2

Sixty-four percent (64%) of trade allies unequivocally felt that high efficiency furnaces were the best choice for their customer (Exhibit 59). Another 22% qualified their responses by saying that it depended upon the customer.

Exhibit 59: Are High Efficiency Furnaces the Best Choice for Customers?

	Percent of Trade Allies
Base (n)	*50*
Yes	64%
No	14%
Sometimes / Depends upon the customer	22%

Exhibit 60 summarizes the reasons, by frequency of mention, why trade allies believe high efficiency furnaces are the best choice for their customers. The most frequently mentioned reason was they save money / are more cost effective (mentioned by 56% of trade allies answering in the affirmative). The next most frequently mentioned reason was that they are more environmentally friendly (26%). Trade allies that said they only sometimes believe a high efficiency furnace is the best choice for the customer or that it depends on the customer were most likely to mention structural constraints present (or not present) in the home as a factor and/or that homeowners found high efficiency furnaces too expensive (data subset not shown)

Exhibit 60: Why Trade Allies Believe High Efficiency Furnaces Are the Best Choice for Customers
Percent of Respondents (Multiple Responses Allowed)

	Percent of Respondents
Base (n)	*43*
Saves money / more cost effective	56%
More environmentally friendly	26%
Structural constraints in home (flue location, electrical panel access)	16%
More energy-efficient	14%
Too expensive for some households	7%
Runs quieter	5%
Provides more even heat	5%
More reliable	2%
Recommend heat pumps / heat pumps more efficient	2%
Other	14%

Totals may not sum due to rounding

Reasons why 14% of trade allies do not believe high efficiency furnaces are the best choice for customers are summarized, by frequency of mention, in Exhibit 61. The most frequently mentioned reason was the preference given to heat pumps (mentioned by 57% of all trade allies who do not recommend high efficiency furnaces). Less frequently mentioned reasons were the expense (14%) and structural issues (14%).

Exhibit 61: Reasons Why Trade Allies Do Not Recommend High Efficiency Furnaces
Percent of Respondents (Multiple Responses Allowed)

	Percent of Respondents
Base (n)	*7**
Recommend heat pumps / heat pumps more efficient	57%
Too expensive for some households	14%
Structural constraints in home (flue location, electrical panel access)	14%
Other	14%

Totals may not sum due to rounding
** Caution is advised when comparing responses based on small samples*

Forty-four percent (44%) of trade allies said they recommend two-stage mid-efficiency furnaces as an alternative to a high efficiency furnace (Exhibit 62). An additional 18% of respondents said it depended upon the customer.

Exhibit 62: Recommend Two-Stage Mid-Efficiency Furnaces as Preferred Option to High Efficiency Furnace?

	Percent of Trade Allies
Base (n)	*50*
Yes	44%
No	38%
Sometimes / Depends upon the customer	18%

The reasons why trade allies recommend / sometimes recommend two-stage mid-efficiency furnaces over high efficiency furnaces are summarized in Exhibit 63. The top two reasons provided by trade allies were that they are a more affordable option for homeowners (mentioned by 26% of trade allies recommending / sometimes recommending two-stage mid-efficiency furnaces), and because the house could not accommodate a high efficiency furnace (16%). Six percent (6%) said it was because the house had a heat pump rather than a furnace.

Exhibit 63: Reasons Why Two-Stage Mid-Efficiency Furnaces Recommended / Sometimes Recommended over High Efficiency Furnaces
Percent of Respondents (Multiple Responses Allowed)

	Percent of Respondents
Base (n)	*31*
Cheaper / More affordable than high efficiency furnace	26%
House cannot accommodate high efficiency furnace	16%
Customer needs / choice	10%
More efficient than single-stage furnace	10%
House has heat pump	6%
More comfortable than single-stage furnace	6%
Next best option to high efficiency furnace	6%
Quieter than single-stage furnace	3%
Uses less electricity than single stage furnace	3%
Other	23%

Totals may not sum due to rounding

The reasons why some trade allies did not recommend two-stage mid-efficiency furnaces as a preferred option to high efficiency furnaces are provided in Exhibit 64. High efficiency furnaces were considered the preferred choice by 32% of trade allies not recommending mid-efficiency furnaces, and 15% of respondents felt there was little price advantage relative to high efficiency models, especially when the Terasen rebate was included. The presence of a heat pump was mentioned by 10% of trade allies.

Exhibit 64: Reasons Why Two-Stage Mid-Efficiency Furnaces Not Recommended over High Efficiency Furnaces
Percent of Respondents (Multiple Responses Allowed)

	Percent of Respondents
Base (n)	*19**
High efficiency furnaces are preferred choice	32%
Little price advantage relative to high efficiency furnaces [especially with rebate]	15%
House has heat pump	10%
Not as efficient as high efficiency furnaces	5%
Other	26%
DK/NR	16%

Totals may not sum due to rounding
** Caution is advised when comparing responses based on small samples*

Ninety-four percent (94%) of trade allies recommend / sometimes recommend variable speed blower motors to their customers (Exhibit 65).

Exhibit 65: Recommend Variable Speed Blower Motors?

	Percent of Trade Allies
Base (n)	*50*
Yes	88%
No	6%
Sometimes / Depends upon the customer	6%

Efficiency (mentioned by 34% of trade allies who recommend / sometimes recommend VSMs), saves money (34%), quieter operation (30%), and improved comfort / more even heat distribution (26%) were the four most frequently mentioned reasons why contractors recommend or sometimes recommend variable speed blower motor-equipped furnaces (Exhibit 66).

Exhibit 66: Reasons Why Contractors Recommend / Sometimes Recommend VSMs Percent of Respondents (Multiple Responses Allowed)

	Percent of Respondents
Base (n)	*47*
Energy-efficient / more efficient	34%
Saves money / saves electricity	34%
Quieter operation	30%
Improved comfort / more even heat distribution	26%
Better quality / last longer	9%
Filtration / better air quality	9%
Continuous operation	4%
Easier to install	2%
More control	2%
Some people have different needs	2%
Other	23%
DK/NR	6%

Totals may not sum due to rounding

Trade allies were asked to indicate the proportion of replacement furnace sales made during the program period by blower motor type – single speed PSC, multi-speed PSC, and VSM. On average, VSM-equipped furnaces represented 47% of sales while Teresan's rebate program was in effect, followed by multi-speed PSC-equipped furnaces (41%), and single speed PSC-equipped furnaces (13%) (Exhibit 67).

Exhibit 67: Distribution of Furnace Sales During the Program by Furnace Blower Motor Type

	Single Speed PSC	Multi-Speed PSC	VSM
Base (n)	*50*	*50*	*50*
0%	54%	6%	10%
1% to 20%	22%	30%	18%
21% to 40%	8%	20%	22%
41% to 60%	4%	14%	16%
61% to 80%	6%	14%	4%
81% to 100%	0%	10%	26%
DK/NR	6%	6%	4%
Total	100%	100%	100%
Mean	*13%*	*41%*	*47%*

Totals may not sum due to rounding

Trade allies who sold VSM-equipped furnaces during the program period said that 24% and 54% of mid-efficiency and high efficiency furnaces respectively sold during the program were equipped with variable speed blower motors (Exhibit 68).

Exhibit 68: Proportion of Furnaces Sold with VSMs – Mid-versus High Efficiency Furnaces

	Percent Sold with VSMs
Base (n)	*50*
Mid-Efficiency Furnaces	24%
High-Efficiency Furnaces	54%

Reasons why their customers purchased a furnace with a variable speed blower motor are ordered by frequency of mention in Exhibit 69. Four reasons were the most frequently mentioned including using less electricity (mentioned by 42% of trade allies), quieter operation (40%), more comfortable ventilation (32%), and the $100 rebate (26%).

Exhibit 69: Customer Reasons for Purchasing a Furnace with a VSM – Contractor's Perspective Percent of Trade Allies - Multiple Responses Allowed

	Percent of Trade Allies
Base (n)	*50*
It uses less electricity	42%
It is quieter	40%
It provides more comfortable ventilation	32%
The $100 rebate	26%
Customer wanted continuous ventilation	16%
It can operate through a range of speeds	6%
Contractor / sales person sold the feature	4%
Customer wanted the "best" furnace	2%
Came with the furnace that was ordered	2%
Other	-
DK/NR	2%

4.4 Furnace Characteristics

Trade allies were asked to estimate the proportion of replacement furnaces they installed during the program period that were eligible for a Terasen incentive. Trade allies reported that, on average, 54% of all furnaces they replaced between September 2005 and March 2007 were eligible for a rebate.

Exhibit 70 summarizes the average remaining life of furnaces replaced while operational. The average of the valid responses (i.e., excluding DK/NR) was 4.7 years. The most frequently recorded response was five years (34% of all responses).

Exhibit 70: Remaining Life of Furnaces Still Operational When Replaced

	Value
Base (n)	*50*
1 Year or less	16%
2 to 5 years	58%
More than 5 years	20%
DK/NR	6%
Total	100%
Mean	*4.7*

4.5 Frequency and Impact of Heat Loss Calculations

The correct sizing of a furnace is important for maximizing the cost effectiveness of a new furnace and is determined by conducting a heat loss calculation. A heat loss calculation determines the amount of heating in GJ (i.e., the size of furnace) needed to replace the heat lost from a home during the cold winter months. Heat loss calculations consider several variables including the square footage of the home, the number, type, and orientation of windows, outside wall construction, insulation thickness, and size of exterior doors. While the particular method used to determine heat loss were not queried, contractors have access to heat loss/furnace sizing methodologies provided by the Canadian Standards Association (CAN/CSA F280) and the Heating, Refrigeration, and Air Conditioning Institute of Canada (HRAI).[6]

Of the trade allies surveyed, 78% said they routinely conduct a heat loss calculation prior to installing the furnace, significantly higher than 48% of trade allies surveyed in 2004. Although the proportion of trade allies conducting a heat loss calculation has improved, the percentage of the calculations that lead to the installation of small capacity furnace varies depending upon the trade ally (Exhibit 71).

Exhibit 71: Share of Heat Loss Calculations that Lead to Smaller Capacity Furnace Percent of Trade Allies That Routinely Conduct a Heat Loss Calculation

	Percent of Trade Allies
Base (n)	*39*
0%	8%
1% to 10%	15%
11% to 50%	21%
51% to 80%	18%
81% to 100%	28%
DK/NR	10%
Total	100%
Mean	*55%*

Totals may not sum due to rounding

On average, contractors estimated that the heat loss calculation leads to a recommendation to install a smaller capacity furnace in more than half (55%) of the cases.

[6] Source: Canada Housing and Mortgage Corporation, www.cmhc-schl.gc.ca/en/co/renoho/refash/refash_018.cfm

4.6 Furnace Fan Usage

Trade allies were asked questions regarding the operating behaviours of furnace fans before and after the furnace change-out. Fan operation after the change-out was differentiated by furnaces equipped with PSC versus VSM blower motors. The results from these questions are summarized in Exhibit 72.

Exhibit 72: Trade Ally Perspective on Pre- and Post-Replacement Furnace Fan Behaviours

	All Replaced Furnaces	New Furnaces with PSC Motors	New Furnaces with VSM Motors
Base (n)	*50*	*50*	*50*
Intermittently when providing heat	30%	30%	26%
Continuously during the heating season	17%	16%	13%
Intermittently when providing heat or air conditioning	29%	23%	21%
Continuously during the heating / cooling seasons	6%	5%	9%
Intermittently to also provide ventilation for part of the year	6%	6%	6%
Continuously	15%	16%	28%
DK/NR	22%	20%	21%

Totals may not sum due to rounding

Trade allies installing VSM-equipped furnaces reported a significant increase in the continuous use of the furnace fan (increase from 15% of pre-retrofit furnaces to 28% of post-retrofit furnaces equipped with VSM blower motors) and a decline in the percentage of furnace fans operating intermittently to provide heat or air conditioning (29% to 21%).

4.7 Program Design Issues

All but one of the 50 trade allies surveyed (98%) were familiar with Energy Star label for natural gas furnaces. Of these, 90% recommended Energy Star natural gas furnaces to their customers, and another 4% said they sometimes recommended them depending upon the customer's requirements. Six percent of trade allies do not recommended Energy Star natural gas furnaces (Exhibit 73).

Exhibit 73: Energy Star Furnaces Recommended to Customers?

	Percent of Trade Allies
Base (n)	*50*
Yes	90%
No	6%
Sometimes / Depends on the customer	4%
Total	100%

Totals may not sum due to rounding

Eighty-two percent (82%) of trade allies felt customers had enough information to make an informed decision about the choice of furnace (Exhibit 74). Another four percent qualified their response by saying that customers sometimes had sufficient information or that it depended upon the customer.

Exhibit 74: Do Customers Have Enough Information to Make an Informed Decision on Choice of Furnace?

	Percent of Trade Allies
Base (n)	*50*
Yes	82%
No	14%
Sometimes / Depends on the customer	4%
Total	100%

Totals may not sum due to rounding

The comments from the handful of trade allies who answered no to this question are listed verbatim in Exhibit 75. Trade allies suggested that households rely upon contractors to educate them on mid-to high efficiency furnaces. This education process includes both the mechanics of upgrading to a high efficiency furnace, and placing the furnace prices in the context of expected savings.

Exhibit 75: Information Missing Regarding the Choice of Furnace Efficiency Percent of Respondents

	Percent of Respondents
Base (n)	*9**
Some don't understand about the mid-efficiency furnace.	2%
Some understand the mechanics, and some have no idea at all.	2%
Terasen doesn't explain it.	2%
The efficiency for high efficiency is so much higher. This is what they want, but they get a price regarding that and basically walk away.	2%
They are missing everything without us to explain it to the customers.	2%
They are not informed of the actual savings they will receive by installing the high efficiency furnace.	2%
They are not well informed about furnaces until they speak with us.	2%
They don't know how they [furnaces] work	2%
DK/NR	2%

** Caution is advised when comparing responses based on small samples*

Seventy-eight percent (78%) of trade allies felt customers had sufficient information to choose between a PSC or VSM-equipped furnace (Exhibit 76). Another 6% said they sometimes had sufficient information or that it depends upon the customer.

Exhibit 76: Do Customers Have Enough Information Regarding the Choice of a PSC or Variable Speed Furnace Motor?

	Percent of Trade Allies
Base (n)	*50*
Yes	78%
No	16%
Sometimes / Depends on the customer	6%
Total	100%

Feedback from trade allies who felt households did not have enough information regarding the choice of furnace motor blower type is listed in Exhibit 77. Several alluded to the tendency for customers to use contractors to explain the differences and/or benefits of the different blower motor technologies. Others referred to barriers associated with building codes, customer lack of interest, uniformed salespeople, or because the trade ally does not recommend furnaces with VSMs.

Exhibit 77: What Information is Missing Regarding the Choice of Furnace Blower Motor? Trade Allies Who Felt Customers Did Not Have Enough Information Regarding the Choice of a PSC or Variable Speed Furnace Motor

	Percent of Respondents
Base (n)	*11**
A lot of them don't know what the effects of the blower motor are.	2%
I don't give information on the variable speed motors because I don't use them.	2%
I explain the differences between the two motors.	2%
I tell them about the efficiency of the motor.	2%
It is hard, especially with the codes, so it depends due to the fact of the codes.	2%
Some people care, and some don't have an interest in it.	2%
Terasen doesn't provide it.	2%
The only way they know is if we tell them, or if they have gone on the internet to find information.	2%
They don't know about how efficient they are. They know the cost may be higher, but that they do pay for themselves.	2%
You can't even teach salespeople because the technicians have all the technical information.	2%
DK/NR	2%

** Caution is advised when comparing responses based on small samples*

4.8 Trade Ally Suggestions – High Efficiency Furnaces

Trade allies were asked how customers could be encouraged to install high efficiency rather than mid-efficiency furnaces. Trade ally suggestions could be grouped by three primary themes: (1) improve education and awareness of high efficiency furnaces, (2) lower the cost of high efficiency furnaces, and (3) improve program delivery. Exhibit 78 summarizes the responses by these three themes.

Exhibit 78: Suggestions on How to Encourage Customers to Choose High-Efficiency Furnaces over Mid-Efficiency Furnaces
Percent of Trade Allies - Multiple Responses Allowed

	Percent of All Trade Allies *
Base (n)	*50*
Improve education and awareness	
Increase emphasis on the benefits of high efficiency furnaces ($ savings, environment, resale value of home)	38%
Increase awareness of rebates (Terasen, federal government, manufacturer, etc.)	4%
Increase the amount of promotion (generic)	2%
Educate customers on construction of their home	2%
Lower the cost of high-efficiency furnaces	
Reinstate rebate	2%
Increase the rebate	10%
Pressure wholesalers to reduce cost	4%
Make dealers offer rebates	2%
Improve size of federal government rebate	2%
Improve program delivery	
Run program year round	4%
Improve access (generic)	2%
More promotion prior to start of heating season	2%
No Suggestions	36%

** Suggestions are not additive as multiple responses were allowed.*

The majority of suggestions made on ways to encourage the adoption of high efficiency furnaces focused on raising the awareness and educating customers about high efficiency furnaces. The majority of suggestions in this sub-group focused on emphasizing the benefits of high efficiency furnaces (mentioned by 38% of all trade allies), including the cost savings, environmental benefits, and improved resale value of the home. The next most common group of suggestions revolved around lowering the cost of high efficiency furnaces through the use of rebates or pressuring dealers and wholesalers to lower their prices. While increasing the amount of the rebate was the most frequently made suggestion in this sub-group, it was mentioned by only 10% of trade allies. A small number of trade allies (2% to 4%) suggested changes to program delivery, including extending the program year round, and increasing the amount of program promotion prior to the start of the heating season. Thirty-six percent (36%) of trade allies did not offer suggestions.

4.9 Trade Ally Suggestions – Blower Motors

Suggestions on how to encourage customers to install variable speed furnace motors rather than the less efficient PSC motors could be arranged by three major subject groups: provide education / raise awareness of VSMs, lower the cost of VSM-equipped furnaces, and/or miscellaneous (other). Exhibit 79 summarizes the suggestions by these three subject areas.

Suggestions related to providing education on the costs, benefits, and operating characteristics of installing furnaces with VSMs were offered by trade allies surveyed. Within this general category, trade allies most frequently mentioned raising the awareness of the cost savings (mentioned by 26% of trade allies). Other benefits cited included air quality, quieter operation, improved comfort, and durability. Consistent with the themes heard throughout the survey, several trade allies suggested that

Terasen emphasize the environmental benefits of VSM-equipped furnaces in their education and awareness programming. As well, several trade allies felt customers needed to be educated on how VSMs work, and how their operating characteristics differ from PSC-equipped furnaces. One trade ally alluded to legislating a ban on the sale of PSC-equipped furnaces, while another felt manufacturers should bear more of the responsibility of increasing VSM sales. Twenty-six percent (26%) of trade allies did not offer any suggestions.

Exhibit 79: Suggested Ways to Encourage Customers to Choose Variable Speed Blower Motors over PSC Motors
Percent of Trade Allies - Multiple Responses Allowed

	Percent of Trade Allies
Base (n)	*50*
Provide Education / Raise Awareness of VSMs	
Raise awareness of benefits – cost savings	26%
Raise awareness (generic)	10%
Educate customers on how they work	8%
Raise awareness of benefits - quieter operation	6%
Raise awareness of benefits - improved air quality	4%
Raise awareness of benefits - comfort	4%
Raise awareness of benefits - environment	2%
Raise awareness of benefits - last longer	2%
Lower the cost of VSM-equipped furnaces	
Increase rebate	22%
Reduce cost of VSMs	2%
Other	
Make VSMs the only choice	2%
Make manufacturers take more responsibility	2%
No suggestions	26%

4.10 Prices

Trade allies provided typical equipment and installed prices for a 90,000 Btu/hour mid-efficiency furnace, a 90,000 Btu/hour high efficiency furnace, and a 75,000 Btu/hour high efficiency furnace. The means of the responses for each furnace type are provided in Exhibit 80. The difference between the mean equipment and installed price effectively represents an approximation of the installation cost.

Exhibit 80: Mean Equipment and Installed Furnace Prices

	90,000 BTU/Hr Mid-efficiency	90,000 BTU/Hr High Efficiency	75,000 BTU/Hr High Efficiency
*Base (n)**	*37-39*	*39-41*	*37-40*
Equipment Price (a)	$1,569	$2,246	$1,925
Installed Price (b)	$2,487	$3,452	$3,183
Installation (b-a)	$918	$1,206	$1,258

** base varies because of differing proportions of DK/NR*

The average equipment price for a 75,000 Btu/hour high efficiency furnace was 23% more than a 90,000 Btu/hour mid-efficiency furnace. Because of its higher efficiency, a 75,000 BTU/hour high efficiency furnace is comparable in its output to a 90,000 BTU/hour mid-efficiency furnace. Installation costs were also higher for the higher efficiency model (37% more), likely reflecting the need to vent the furnace through the side of the house and higher set up costs. Including equipment and installation costs, a 75,000 BTU/hour high efficiency furnace costs 28% more than a 90,000 BTU/hour mid-efficiency furnace.

Equipment costs for a 90,000 Btu/hour high efficiency furnace were significantly higher than a 75,000 Btu/hour high efficiency furnace, commensurate with its size. Installation costs, however, did not statistically differ between the two models.

4.11 Free Riders

Trade allies were asked to rate the importance of the Terasen rebate in their customers' choice of furnace efficiency on a five point scale, where five represented "very important" and one was "not at all important". Trade allies gave an average importance rating of 3.7 out of 5.0. Exhibit 81 uses weights to derive the trade ally based estimate of free riders. A weight of 1 is given to the highest score, 0.75 to the next, 0.5 to the next, and so on. Weights of zero were assigned to an importance score of 1 or DK/NR. Using this method, 66% of trade allies felt the rebate influenced their customers' choice of furnace efficiency, implying a free rider rate of 33%.

Exhibit 81: Trade Ally Estimate of Free Riders – Influence of Overall Incentive

	Very Important (5)	(4)	(3)	(2)	Not at all Important (1)	DK/NR	Total	Free Rider Rate
Distribution of Responses (n=50)	34%	24%	20%	14%	4%	4%	100%	-
Weight	1	.75	.50	.25	0	0	-	-
Product	0.34	0.18	0.10	0.04	0.00	0.00	0.66	**0.33**

Trade allies were next asked to rate the importance of the $100 rebate that was offered to customers who purchased a VSM-equipped furnace. Trade allies gave an average importance score of 3.2 out of 5.0. Using weights identical to those used with the previous question, it is estimated that 53% of customers receiving the VSM rebate would not have purchased the VSM-equipped furnace if the rebate had not been available (Exhibit 82). This suggests a free rider rate for the VSM incentive of 47%.

Exhibit 82: Trade Ally Estimate of Free Riders – Influence of VSM Incentive on Blower Motor Choice

	Very Important (5)	(4)	(3)	(2)	Not at all Important (1)	DK/NR	Total	Free Rider Rate
Distribution of Responses (n=50)	20%	26%	18%	18%	16%	2%	100%	-
Weight	1	.75	.5	.25	0	0	-	-
Product	0.20	0.20	0.09	0.05	0.00	0.00	0.53	**0.47**

The next section compares and discusses the relative merits of the free rider estimates derived from trade ally data versus those derived from the customer survey. Based on that discussion, the decision was made to use the customer survey based free rider estimates in the calculation of program impact.

5 Impact Analysis

This section summarizes the analysis and calculations used to derive a preliminary estimate of energy savings associated with Terasen's 2005-07 Heating System Upgrade Program. Key factors influencing net program savings include attribution (free riders), spillover (advancement of the furnace replacement decision), and operational/behavioural changes. Estimates of program savings are preliminary at this point and will be revised using a comparison of billing histories for participants and non-participants (billing analysis). The billing analysis will occur after participants have used their new furnaces for one full heating and cooling season (12 months). This will allow a comparison of their energy use patterns pre- and post-furnace change-out and will factor in behavioural changes using a comparable group of non-participants. Behavioural changes at this stage of the program's evaluation are limited to description and discussion only.

5.1 Operational/Behavioural Changes

Following the decision of which furnace model to purchase, homeowners can influence the amount of savings realized from the operation of their new furnace in three primary ways:

- pre-post changes in the furnace fan use;
- pre-post changes in furnace settings, most importantly the thermostat or fan operating settings; and
- pre-post changes in the use of supplementary heating.

5.2 Furnace Fan Use

How homeowners use their furnace to heat or cool the house, or to provide ventilation either occasionally or continuously, ultimately affects the amount of energy savings realized from installing a VSM-equipped furnace (assuming their old furnace used a PSC motor). These behaviours also influence the program's economics that justify incentives encouraging the adoption of VSM-equipped furnaces. The economics of VSM blowers are such that households that tended to use their old PSC-equipped furnaces to provide heating/cooling on a continuous basis, and/or to run their fans intermittently to provide ventilation or air circulation, will realize the greatest electricity savings from switching to a furnace with a VSM blower motor. Households that use their fans only intermittently to provide heating or cooling realize considerably less savings. In short, insufficient operating hours significantly increases the payback period for VSM-equipped furnaces. Data from the customer and trade ally surveys on furnace fan behaviours before and after replacing the furnace were analyzed to better understand the cost effectiveness, and targeting, of the VSM incentive.

Information on fan usage from the customer survey was recombined to create four primary groups of fan use – intermittent (heat / cool season), continuous (heat / cool season), to provide ventilation, and continuous. These results were then cross-tabulated by the type of furnace blower motor on the new furnace (PSC versus VSM). Participants and non-participants were combined by furnace blower motor choice to facilitate interpretation. The distribution of fan use for the two motor types was rebased to exclude DK/NR and households without furnace fans (boilers). The results of this analysis are presented in Exhibit 83.

Exhibit 83: Pre-Post Furnace Fan Behaviours by Blower Motor Type (Customer Survey) Participants and Non-Participants Combined

	Before		After		Net Change	
Post Furnace Change Motor Type >	**PSC**	**VSM**	**PSC**	**VSM**	**PSC**	**VSM**
Base (n)	33	98	32	96	-	-
Intermittently (heat / cool season)	55%	60%	47%	52%	-8%	-8%
Continuously (heat / cool season)	36%	31%	41%	32%	+5%	+1%
To also provide ventilation	3%	4%	6%	7%	+3%	+3%
Continuously	6%	5%	6%	8%	0%	+3%

The data suggest that relatively fewer households from both groups – those who installed PSC-equipped furnaces and those who installed VSM-equipped furnaces – are using their new furnace to intermittently heat or cool their homes during the heating/cooling seasons (8% of households for each group). The proportion of households using their furnace fan to provide continuous heat or cooling during the heating / cooling seasons also increased although a larger proportion of PSC households (+5%) did versus VSM-equipped households (+1%). The proportion of households that use their fan to provide ventilation for part of the year increased equally for both groups (+3%); however the proportion of VSM-equipped households that use their fans continuously increased by 3%.

Based on the data presented in Sections 3 and 4 of this report, and this analysis, there are several observations that can be made. One, households that replaced their old PSC-equipped furnace with a VSM-equipped furnace are comprised of several user types. Two, some households have changed how they use their furnace fan after installing their new furnace. Some have gone from using their furnace fan intermittently to continuous use or to provide ventilation, while others have not changed their behaviours – using their furnace fan only on an intermittent basis (yielding the least electricity savings), or running their fan continuously or to provide ventilation in the pre-post periods (highest electricity savings from switching to VSMs). The amount of electricity savings is directly related to pre-post operating hours of the furnace fan, thus the economics of the VSM incentive will depend upon the relative proportion of those who tended to use their fan the most in the pre-change out period and continue to do so afterwards. Finally, there is also evidence that, regardless of motor type, some households have used the furnace replacement decision as an opportunity to add air conditioning. A similar observation was made in the 2004 evaluation (Habart 2004). Finally, while electricity use for both PSC and VSM users will increase due to the addition of air conditioning, those with VSMs should realize some savings relative to PSC-equipped furnaces as VSMs give off less heat than PSC motors.

The finding that some households that installed PSC-equipped furnaces have increased their use of the furnace fan to provide continuous heat/cooling or to provide ventilation for part of the year may be due to improvements in the operating characteristics of the new furnace (e.g., two-stage burner, multi-speed PSC fan motor).

Data from the customer survey suggests that households that had higher operating hours for their old furnace fan (i.e., operated their fans continuously or for air circulation / ventilation) were no more likely to purchase a furnace equipped with VSM than those who had lower operating hours. Instead, energy efficiency and the recommendation of the contractor appear to be relatively more important than the desire for improved circulation / ventilation for many households that purchased a furnace equipped with a VSM blower (Exhibit 31, p. 25). It may be that some of these households were expecting significant electricity savings, but because they used their fan only intermittently prior to the furnace change-out they have been disappointed. Indeed, households with VSM-equipped furnaces rated their satisfaction with the electricity bill savings as 3.8 out of 5.0, significantly lower than the 4.2 satisfaction rating assigned by households who installed PSC-equipped furnaces (Exhibit 19, p. 18). There is also sufficient evidence to suggest that the non-energy benefits of purchasing a high efficiency furnace equipped with a VSM motor (e.g., improved comfort, improved air quality via air circulation, pollen filters, etc.) influenced the decision to purchase the furnace, and is influencing how that furnace is now operated. Non-energy benefits are common selling features for VSM-equipped furnaces.

Information on the before and after use of the furnace fan provided by trade allies was reviewed to provide alternative insight into furnace fan operating behaviours. Trade allies were questioned about fan usage for furnaces they replaced (the majority of these are assumed to be PSC equipped furnaces), newly installed PSC equipped furnaces, and newly installed furnaces with VSMs. Trade allies were not asked about operating behaviours for replaced VSM equipped furnaces as very few VSM models were available prior to 2000 and thus very few households would be replacing a VSM equipped furnace.

Exhibit 84 summarizes the trade ally data organized into the four operating behaviour groupings, rebased to eliminate non-responses (DK/NR). Compared to the old furnace, newly installed VSM-equipped furnaces were more likely to have their fans operate continuously (up from 15% to 27%) and less likely to operate intermittently during the heating / cooling seasons (down from 57% to 46%).

Exhibit 84: Pre-Post Furnace Fan Behaviours by Blower Motor Type (Trade Ally Survey) Percent of Households

	PSC Furnaces		VSM-Equipped Furnaces	Net Change	
	Before	After	After	PSC Equipped Furnaces	VSM-Equipped Furnaces **
Base (n) *	38-40	38-39	37-38	-	-
Intermittently (heat / cool season)	57%	56%	46%	-1%	-11%
Continuously (heat / cool season)	22%	21%	21%	-1%	-1%
To also provide ventilation	6%	6%	6%	0%	0%
Continuously	15%	17%	27%	+2%	+12%

* *Excludes DK/NR*
** *VSM equipped furnaces compared to PSC furnaces*

Compared to the customer surveys, the trade ally data suggest a significantly larger increase in the proportion of households that shift from intermittent to continuous use. It also suggests no change in the relative proportion of households using their furnaces either continuously to provide heat or cooling, or to provide ventilation.

5.3 Changes to Furnace Operating & Control Settings

Exhibit 85 shows that 22% of participants and 9% of non-participants are setting the thermostat lower during the winter months compared to before they replaced their furnace. Only 4% of participants and 11% of non-participants have adjusted their thermostat to keep their house warmer compared to before the furnace change out.

When participants who turned up their thermostat are added to those who turned down their thermostat and those who made no change, the net change in indoor temperature for participants as a group is negative (-0.6^{o} Celsius). It may well be that the increase in home comfort associated with the high efficiency furnaces (e.g., less temperature variation between rooms, better temperature maintenance between furnace cycles, etc.) led participants to lower their thermostat. This, everything else held constant, should increase energy savings somewhat.[7]

Exhibit 85: Average Degree (Celsius) Change in Thermostat Setting since Furnace Change Winter Months

	Change in Indoor Temperature Post-Installation		Amount Warmer / Cooler (Degrees Celsius)		
	Participants	Non-Participants	Participants	Non-Participants	All Respondents
Base (n)	100	100	*100*	*100*	*200*
Warmer	4%	11%	4.7	5.0	4.9
Cooler	22%	9%	3.3	2.5	2.9
No Change	67%	70%	0.0	0.0	0.0
DK/NR/Too soon to tell	7%	10%	-	-	-
Net Change	-	-	-0.6	0.4	-0.2

** Weighted average change including no change (0^o)*

In contrast to participants, non-participants, overall, increased their thermostat setting by 0.4 degrees Celsius. When combined with the 0.6 degree Celsius decline in temperature reported by participants, this suggests that participation in the Terasen furnace program results in a one degree reduction in average temperature setting, and should, everything else held constant, add to participant savings. The forthcoming billing analysis will implicitly capture any relative differences in temperature setting.

5.4 Other Changes to Furnace Settings

Only 5% of participants and 1% of non-participants reported changing one or more operating settings on their furnace (other than the thermostat setting). The relatively small number of households changing their furnace settings, and the nature of the changes identified (e.g., changing the furnace to run less frequently, resetting the blower, installing a digital readout, and installing air conditioning, etc.) suggest these changes are too small to be isolated in determining program savings – using either an engineering estimate or billing analysis approach.

5.5 Changes in Supplemental Heating

Changes in the use of supplementary heating following the installation of the new furnace has the potential to increase or decrease the savings from the furnace upgrade. Reduced use of a supplemental heat source following the furnace change-out means that, everything else held constant, the heating load carried by the natural gas furnace should increase. If the displaced secondary fuel is electricity, then pre-post bill savings for natural gas will be reduced.[8] However, if the secondary fuel is natural gas, then savings are likely increased as the high efficiency furnace will be more efficient that the secondary heat source, such as a fireplace.

Data from the customer survey regarding supplementary heat sources, and the fuel type for supplementary heat, revealed that natural gas fireplaces are the most common source of supplementary

[7] Natural Resources Canada's website suggests that a 1 degree reduction in thermostat setting translates into a 2% reduction in heating costs (www.nrcan.oee.nrcan.gc.ca).

[8] The program should receive credit for the electricity savings in the Total Resource Cost test. However, there is insufficient data in the evaluation methodology to estimate this impact accurately.

heating; present in 41% of participant homes.[9] This suggests that natural gas savings should increase somewhat in these homes if the new high efficiency furnace picks up some or all of the heating load previously carried by the lesser efficient natural gas fireplace.

Exhibit 86 shows that the majority of participants and non-participants (52% and 53% respectively) indicated their use of supplementary heating had not changed since installing their furnace.

Exhibit 86: Change in Supplementary Heating Use since Furnace Replacement Among Those with Supplementary Heating

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*88*	*48*	*40*	*20**	*50*	*18**
Increase	8%	6%	10%	5%	12%	0%
Decrease	30%	33%	25%	35%	32%	17%
Stay the Same	52%	52%	53%	45%	48%	72%
DK/NR	10%	8%	13%	15%	8%	11%
Total	100%	100%	100%	100%	100%	100%

** Caution is advised when comparing responses based on small samples*

If the data are rebased to exclude the differing number of non-responses for the two groups (data not presented in tabular format), the proportion of participants reporting a decrease in their use of supplemental heat increases to 36% (rebased) from 33% (non-rebased). Using the same rebasing technique, the proportion of non-participants reporting a decrease in supplemental heating increased to 29% from 25%. The proportion of participants and non-participants reporting increased use of supplemental heating represented 7% and 11% of the two groups, respectively, up from 6% and 10% respectively in the non-rebased series.

The amount of the decrease in supplementary heating, reported in one-quarter increments, is summarized in Exhibit 87. The estimated mean change was calculated by taking the mid-point value of each range (e.g., 0% to 24% was set to 12%, 25% to 49% was set to 37%, and so on) and weighting them by the proportion of responses for each range. This approach provides an approximate indication of relative differences in the reduction in supplementary heating use for participants compared to non-participants.[10] In this case, participants who decreased their use of supplementary heating, cut their use of supplementary heating by almost half (average reduction of 45%). In contrast, non-participants who reduced their use of supplementary heating, did so by 22% on average. A similar calculation was conducted for those who increased their supplementary heating (Exhibit 88).

[9] Determined by cross tabulating supplementary heat sources against fuel types used for supplementary heating. Table not shown.

[10] This procedure allows a comparison of the relative change and direction of change in supplementary heating use by a number of criteria such as program participation and type of blower motor. The comparisons are largely illustrative as the relative amount of energy used for supplementary heating prior to the furnace change is not known, only the relative change since installing the new furnace.

Exhibit 87: Amount of Decrease in Supplementary Heating since Furnace Replacement

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*24**	*16**	*10**	*7**	*16**	*3**
0% to 24%	5%	5%	5%	57%	31%	33%
25% to 49%	4%	5%	3%	-	38%	67%
50% to 74%	1%	2%	-	-	13%	-
75% to 100%	2%	4%	-	14%	19%	-
DK/NR	1%	-	2%	29%	-	-
Total	100%	100%	100%	100%	100%	100%
Estimated Mean Decrease **	37%	45%	22%	28%	42%	29%

Totals may not sum due to rounding
** Caution is advised when comparing responses based on small samples*
*** Calculated as the response weighted average of the mid-points for each response category*

Exhibit 88: Amount of Increase in Supplementary Heating since Furnace Replacement

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*7**	*3**	*4**	*1**	*6**	-
0% to 24%	43%	33%	50%	100%	33%	-
25% to 49%	14%	-	25%	-	17%	-
50% to 74%	0%	-	-	-	-	-
75% to 100%	14%	-	-	-	17%	-
DK/NR	29%	66%	25%	-	33%	-
Total	100%	100%	100%	100%	100%	-
Estimated Mean Increase **	32%	13%	37%	13%	37%	-

Totals may not sum due to rounding
** Caution is advised when comparing responses based on small samples*
*** Calculated as the response weighted average of the mid-points for each response category*

Weighted by the relative proportion that reported an increase, decrease, or no change to their supplementary heating, participants with supplementary heating reported a decrease of 16%, and non-participants recorded a 2% decrease (Exhibit 89). Weighted across all households – with or without supplementary heating – the average decrease in supplementary heating for participants and non-participants is 7% and 1%, respectively.

Exhibit 89: Net Change in Supplementary Heating since Furnace Replacement

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Mean Increase	43%	33%	50%	100%	33%	-
Mean Decrease	14%	-	25%	-	17%	-
Estimated Mean Change *	-9%	-16%	-2%	-11%	-10%	-
Estimated Mean Change All Respondents **	-4%	-7%	-1%	-5%	-4%	-

** includes those with no change in supplementary heating*
*** calculated as the weighted average of those with and without supplementary heating.*
Totals may not sum due to rounding

The results appear to suggest that participants were more likely than non-participants to reduce their use of supplemental heating after replacing their furnace. This suggests that participants' new furnaces are picking up some of the heating load previously met through supplemental sources, most notably the natural gas fireplaces, and to a lesser degree, electric heaters (see Exhibit 47, p. 32).

Estimating the impact on program savings due to the change in supplementary heating, at this point, is problematic due to the considerable number of assumptions required to correctly proportion the heating load borne by the supplementary heating pre- and post-furnace change-out, and to adjust for differing AFUEs of supplementary end use equipment and appliances. Additionally, the heating load transfer may be less than it appears if supplementary heating in the pre-furnace change-out period was needed because of temperature variations between rooms, temperature fluctuations between furnace cycles, and so on – in effect, supplementary heating was being used to improve the comfort in the home or parts of the home. The forthcoming refinement of program savings using a billing analysis will implicitly capture these changes in supplementary heating use and the net impact of other changes in heating/cooling use.

5.6 Market Transformation – Replacement Market

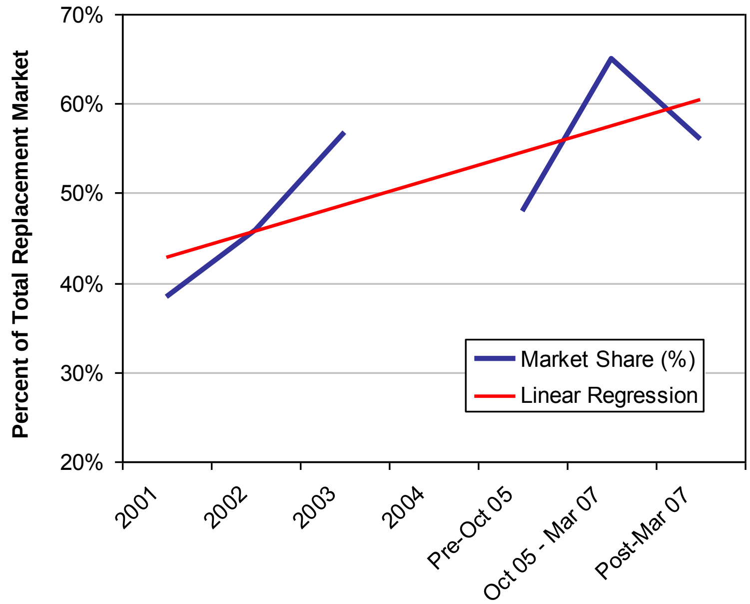
When first introduced to the market, high efficiency technologies are typically priced at a premium compared to standard efficiency units. This "first cost" premium can pose a barrier to the adoption of the technology – one which rebates and other incentives, combined with education and awareness programming, are designed to overcome. The incentives and related programming send signals to manufacturers and suppliers – both in terms of the intent to promote the high efficiency market, and through the eventual increase in demand for the high efficiency product. The mark of successful market transformation programs has been an increase in the awareness and availability of the high efficiency product, and a decline in the price differential between it and lesser efficient models. Understandably, the ability to transform a market depends on the scale and scope of the program, the ability for manufacturers to realize economies of scale, and a host of other factors that influence supply and demand for the technology in the market place.

5.7 Market Shares – High Efficiency Furnaces

Based on results from the survey of trade allies, the proportion of the replacement market captured by high efficiency furnaces saw an increase during the program period. High efficiency furnaces captured 65% of the market while the program was operating, up from 48% prior to launch, and then declining to 56% afterwards. The results from the customer survey suggested that the share of the replacement furnace market captured by high efficiency furnaces was 55% during the program period.

Figure 3 summarizes the replacement market share data from this evaluation and the 2004 evaluation. The data series is imperfect and caution in over-interpreting the results is advised. The time periods are inconsistent and data are missing for 2004, although pre-September 2005 does, by default, infer some overlap. Inserting a simple linear regression trend line suggests an upward trend in the proportion of the replacement furnace market captured by high efficiency furnaces. This was expected. The data does suggest that the market shares fall off after incentives cease. This, too, is expected and is commonly observed with incentive based demand-side management programs.

Figure 3: Shares of High Efficiency Furnaces in the Replacement Furnace Market
Source: Trade Ally Surveys – 2003, 2007



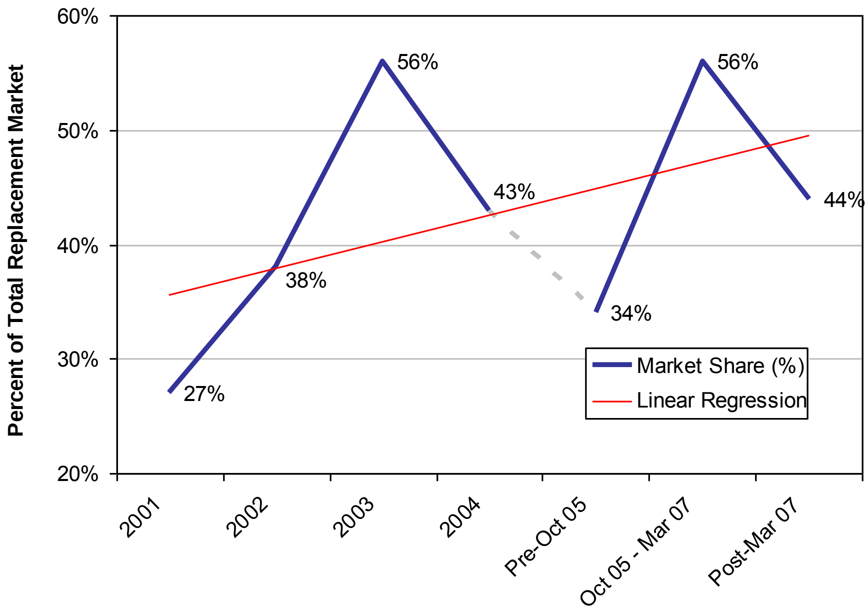
Trade allies reported that, on average, 54% of all furnaces they replaced between September 2005 and March 2007 were eligible for a rebate from Terasen Gas or its partners.

5.8 Market Shares – Variable Speed Motors

According to trade allies, the share of the replacement furnace market represented by furnaces with VSM blower motors increased from 34% in the pre-program period to 56% during the program, and falling to 44% in the post-program period. Data from the customer survey put the share of VSM-equipped furnaces (high or mid-efficiency) at 60%. Focusing just on high efficiency furnaces, Terasen's program records indicate that 65% of participants in the heating upgrade program opted for a high efficiency furnace equipped with a VSM blower motor.

Figure 4 pulls together VSM market share data from the 2004 evaluation and the trade ally estimates for the 2005-2007 period. The data, while imperfect for reasons discussed under furnace efficiency market shares, suggest a seesaw pattern, where VSM shares increase significantly during periods where Terasen's rebate program is in effect.

Figure 4: Share of VSM-equipped Furnaces in the Replacement Furnace Market
Source: Trade Ally Surveys – 2003, 2007



Despite the pullback in the periods following termination of incentives, the general trend in VSM market share for furnaces equipped with VSMs appears to be increasing.

5.9 Prices

For many homeowners, the cost of replacing a furnace (first cost) can be the predominate factor influencing the choice of furnace model efficiency. The relatively greater equipment and installation cost of a high efficiency furnace can become a barrier for households for several reasons: not excluding insufficient funds or access to funds (financing), plans to sell the home in near future (e.g., will not realize the long-term cost savings associated with a high efficiency unit), or a lack of understanding of the lifecycle cost savings from adopting a high efficiency unit.

The trend in prices of high versus mid-efficiency furnaces (i.e., lowest cost option now allowed by legislation) were explored using data from the 2007 trade ally survey and data gathered for the 2004 evaluation (survey conducted in 2003). The results in Exhibit 90 suggest that equipment prices have increased for both mid and high efficiency models over the four-year period. However, on an installed cost basis, a decline in installation costs has offset more than half (57% to 58%) of the increase.

Exhibit 90: Furnace Equipment and Costs for 90,000 BTU/Hr Units - 2007 Versus 2003

	90,000 BTU/Hr Mid-efficiency Furnace			90,000 BTU/Hr High Efficiency Furnace		
	2003	2007	Difference	2003	2007	Difference
Base (n)	*40*	*50*	-	*40*	*50*	-
Equipment Price (a)	$1,104	$1,569	$465	$1,806	$2,246	$440
Installation Charges (b-a)	$1,185	$918	-$267	$1,391	$1,206	-$185
Final Installed Price (b)	$2,289	$2,487	$198	$3,197	$3,452	$255

Exhibit 91 compares installed furnace prices for a 90,000 BTU/hour mid-efficiency furnace and a 75,000 BTU/hour high efficiency furnace for the years 2002, 2003 and 2007. Because of its higher efficiency, a 75,000 BTU/hour high efficiency furnace is comparable in its output to a 90,000 BTU/hour mid-efficiency furnace. The incremental installed cost declined from 2002 to 2003 from $877 to $608 before increasing to $696 in 2007.

Exhibit 91: Installed Furnace Costs – 2002, 2003, 2007

	90,000 BTU/Hr Mid-efficiency Furnace	75,000 BTU/Hr High Efficiency Furnace	Incremental Cost
2002	$2,194	$3,071	$877
2003	$2,289	$2,897	$608
2007	$2,487	$3,183	$696

Exhibit 92 compares the equipment and installation costs for the same two furnaces for the survey years 2003 and 2007. Of note, equipment costs for both furnaces are higher in 2007. In the case of the 90,000 BTU mid-efficiency furnace, a decline in the average installation cost has partially offset the $465 dollar increase in equipment cost. For the 75,000 BTU high efficiency model, equipment costs rose by $277 but installation costs were effectively unchanged.

Exhibit 92: Equipment and Installation Cost Comparisons - 2007 Versus 2003

	90,000 BTU/Hr Mid-efficiency Furnace			75,000 BTU/Hr High Efficiency Furnace		
	2003	2007	Difference	2003	2007	Difference
Base (n)	*40*	*50*	*-*	*40*	*50*	*-*
Equipment (a)	$1,104	$1,569	$465	$1,648	$1,925	$277
Installation Charges (b-a)	$1,185	$918	-$267	$1,249	$1,258	$9
Final Installed Cost (b)	$2,289	$2,487	$198	$2,897	$3,183	$286

The comparison of equipment and installation costs for the past two survey periods fails to provide an indication that the differential between a comparable mid-efficiency and high efficiency furnace has narrowed. Equipment prices for all models appear to have increased over the four year period. Installation costs for high efficiency models still remain higher than a mid- or standard efficiency unit.

5.10 Free Riders

5.10.1 Free Riders – High Efficiency Furnaces

The results from the participant and trade ally surveys provided two estimates of the free rider rate for high efficiency furnaces rebated under the Terasen program, with the participant survey suggesting 43% and the trade ally survey suggesting 33%. The relatively high proportion (58%) of non-participants who installed a high efficiency furnace but were unaware of Terasen's heating upgrade program (Exhibit 93) suggests that the free rider rate is probably closer to that estimated using participant survey data. The non-participant data should be interpreted with caution, as there is evidence that some have difficulty in accurately identifying the efficiency level of their furnace.

Exhibit 93: Non-Participant Furnace Efficiency Choice by Awareness of Terasen's Program

	Total	Aware	Unaware & DK/NR
Base (n)	*100*	*48*	*52*
Standard Efficiency	39%	48%	31%
High Efficiency	48%	38%	58%
DK/NR	13%	15%	12%
Total	100%	100%	100%

Totals may not sum due to rounding

5.10.2 Free Riders – Variable Speed Drives

The free rider rate for variable speed drives represents the proportion of participants who received the $100 incentive for purchasing a VSM-equipped furnace but would have purchased a VSM-equipped furnace without the incentive. Again, the participant and trade ally surveys provided two estimates of the free rider rate for VSMs. The participant survey suggested a free rider rate of 43% while the trade ally survey suggested a slightly higher rate of 47%. Which estimate is closer to the true rate is subject to interpretation.

The relatively high estimates are consistent with evidence that suggests the incentive was less instrumental in the decision to purchase than, for example, the potential to save energy or the recommendation of the furnace dealer/contractor (Exhibit 31, p. 25). The customer survey indicates that 34% of participants and 36% of non-participants who purchased a VSM-equipped furnace indicated they were aware of VSMs or considering the purchase of VSMs prior to purchasing their furnace. These households are most likely to be classed as potential free riders. However, awareness, while fundamental to the consideration of a VSM in the first place, doesn't necessarily ensure the choice of VSM-equipped furnace in the final decision by the consumer.

Exhibit 94 looks at the issue from the non-participant's perspective. The data suggest that 53% of non-participants who were unaware of Terasen's Heating System Upgrade Program purchased a furnace with a VSM. While this lends support to the use of the trade ally estimate, the free rider estimate of 43% derived from the participant survey will be used for determination of net impact because it was derived in a manner consistent with the free rider rate for high efficiency furnaces in general.

Exhibit 94: Non-Participant Blower Motor Choice by Awareness of Terasen's Program

	Total	Aware	Unaware & DK/NR
Base (n)	*70*	*32*	*38*
PSC	44%	41%	47%
VSM	56%	59%	53%
Total	100%	100%	100%

Totals may not sum due to rounding

5.11 Spillover

There are several reasons why households replace their old furnaces. Some furnaces cease working and require expensive repairs, while others are diagnosed as needing expensive repairs in the not-so-distant future. Some households will choose to replace their older, inefficient furnaces to realize energy savings or to improve the comfort in the home. However, change-outs such as these typically occur only when the furnace is nearing the end of its useful life.[11] Finally, some households made the decision to replace their furnace earlier than planned because of the availability of incentives, such as those offered through the Terasen Heating System Upgrade Program. The energy savings realized from advancing the decision to replace the furnace that can be attributed to Terasen's program are termed spillover savings. They are calculated by taking the difference in the efficiency levels of the replaced furnace and the new furnace, and multiplying the savings by the average number of years of advancement.

Spillover savings for Terasen's 2005-07 Heating System Upgrade Program were determined by querying participants about the operational status of their old furnace at the time of replacement, and then asking them whether the program caused them to advance their decision to replace the furnace. Finally, those participants who answered in the affirmative to both questions were asked to indicate by how many years they advanced their decision.

The customer survey found that 91% of participants' furnaces and 77% of non-participants' furnaces were still working and producing heat when replaced. The average age of the furnace at the time of replacement for participants was 24.1 years versus 24.7 years. These statistics confirm that participants were more likely to replace their furnaces prior to failure, and at an earlier age. Thirty percent (30%) of participants confirmed that they replaced their furnaces earlier than planned because of the availability of the rebate. They indicated an average advancement of 2.3 years.

5.12 Calculation of Program Savings

5.12.1 Key Inputs and Assumptions

Average AFUE for Rebated Furnaces

Program records listed brand names and corresponding model numbers, but not AFUE ratings for the rebated furnaces. To determine the average AFUE rating of the new high efficiency furnace for use in the impact calculations, a random sample of 400 participant furnaces were manually cross-referenced with the Energy Star database of qualifying natural gas furnaces.[12] Matching was based on the furnace brand name and model number. Where matches were not possible, the records were excluded from calculation of the AFUE average.[13] In cases where the Energy Star database listed a range of AFUE for a particular furnace model (e.g., 90.1% – 92.0%) , the lower AFUE rating was selected. In the end, 362 of the 400 participant records were matched successfully to an AFUE rating yielding an average AFUE rating of 93.0%. The previous evaluation had used an assumption of 92% AFUE.

AFUE and Average Consumption of Replaced Furnace Stock

Current legislation in British Columbia prohibits the sale of natural gas furnaces with an AFUE of less than 78%, defining the minimum efficiency base for calculating program savings. A billing analysis conducted for the 2002 Residential Heating System Upgrade program determined that the efficiency of the average furnace replaced during that year's program was 70.6%. As an update to this value is not available, it will be used for this analysis. The same study estimated the annual consumption of the average replaced furnace was 91.5 GJ. As an update to this value is not available, it will be used in the phase one impact analysis as well.

[11] Only 14% of households surveyed indicated their replaced furnace was younger than 15 years.

[12] The database is available for download from *http://www.energystar.gov/index.cfm?c=furnaces.pr_furnaces*

[13] Model numbers for gas furnaces can vary significantly between manufacturers, with most using lengthy alphanumeric combinations. Some of the model numbers recorded in the program database were either incomplete or had typographical errors making it impossible to accurately match the furnace model to the Energy Star database.

Number of Participants

Based on program records, 8,652 customers participated in the Terasen program during the September 2005 to March 2007 period. Of these, 5,667 applicants received an incentive for a VSM-equipped furnace.

Free Riders

Free riders in the overall program were estimated at 43%. Free riders among those participants receiving an incentive for a VSM-equipped furnace were calculated as 43%.

Spillover

Thirty percent (30%) or 2,596 participants indicated that they replaced their furnace earlier than planned because of the Terasen program. The average number of years of advancement for these customers was 2.3 years.

5.13 Energy Savings

The estimated energy savings attributable to Terasen's 2005-07 residential Heating System Upgrade Program is summarized in Exhibit 95. Based on a net-to-gross ratio of 0.57, the program generates 66.1 terajoules (TJ) in annual savings, plus an additional 22.6 TJ of savings for the first 2.3 years (spillover).

Exhibit 95: Energy Savings Estimates – September 2005-March 2007

	Unit Savings (GJ)	Gross Participants	Gross Savings (TJ)	Net to Gross Ratio	Net Savings (TJ)
Direct	13.4	8,652	115.9	0.57	66.1
Spillover	8.7	2,596	22.6	--	22.6
Annual – first 2.3 years	-	-	-	-	88.7
Annual – subsequent years	-	-	-	-	66.1

5.14 Peak Day Reductions

To estimate peak savings, the heating load on any day is assumed proportional to the heating degree days for that day. In the coldest month (January) the average daily heating load is equal to:

Annual Heating Load (GJ) * Monthly Share of Annual Heating Degree Days (January) * 1/31 days

The change in peak day load is then calculated as the change in average daily load for January. Exhibit 96 calculates the weighted peak day heating load share for January using a representative weather station for each of Terasen's five zones and the thirty year typical meteorological year heating degree-day shares for the month. Estimated peak day savings are then calculated as the weighted peak day heating load share for January multiplied by net savings. Estimated peak day savings are 0.48430 TJ for the first 2.3 years, and then 0.36091 TJ for the remaining years.

Exhibit 96: Peak Day Savings

	Representative Weather Station	Zone Customer Share	Peak Day Heating Load Share	Weighted Peak Day Heating Load Share	Peak Day Savings (TJ) – First 2.3 years (Including Spillover)	Peak Day Savings (TJ) – Remaining Years
Zone 1	Vancouver	0.244	0.00501	0.00122	-	-
Zone 2	Burnaby	0.173	0.00511	0.00084	-	-
Zone 3	Surrey	0.280	0.00510	0.00143	-	-
Zone 4	Kamloops	0.117	0.00625	0.00073	-	-
Zone 5	Cranbrook	0.186	0.00667	0.00124	-	-
Total	-	1.000	-	0.00546	0.48430	0.36091

5.15 Carbon Dioxide Reductions

Terasen assumes an emissions factor of 50 tonnes carbon dioxide (CO_2) per terajoule of energy saved. Using this factor allows the saving estimates to be translated into the equivalent reduction in CO_2 emissions (Exhibit 97). In total, the program reduced the amount of annual CO_2 emitted by residential furnaces by 4.435 kilotonnes in the first 2.3 years, and 3.305 kilotonnes for subsequent years.

Exhibit 97: Reduction in Carbon Dioxide Emissions

	Net Savings (TJ)	Emissions Factor	$C0_2$ Reduction (Kilotonnes)
Direct	66.1	0.050	3.305
Spillover	22.6	0.050	1.130
Total – first 2.3 years	88.7	0.050	4.435
Total – Remaining Years	66.1	0.050	3.305

6 Summary & Conclusions

Summary comments and conclusions for the evaluation of Terasen's 2005-07 Heating System Upgrade Program are organized by the five main evaluation objectives.

Objective 1: Assess the reasons for program participation, the effectiveness of program marketing / advertising, free ridership, reasons for non-participation, and overall customer and trade ally satisfaction with the program.

Understanding the importance of Terasen's Heating System Upgrade Program to the decision to install a high efficiency rather than a standard or mid-efficiency furnace is essential to the attribution of energy savings to Terasen's program. In this regard, 57% of participants in the Terasen program credited the program with influencing their decision to purchase a high efficiency furnace, meaning that 43% of participants were free-riders and would have selected a high efficiency furnace without the incentive. The free rider estimate is consistent with the fact that 38% of non-participants that were unaware of the Terasen program installed a high efficiency furnace. Based on information provided by participants, the proportion of free riders for the 2005-07 program is estimated at 43%. This is an increase from 28% estimated for the previous program. The increase is consistent with the continuing transformation of the furnace market to high efficiency units.

Thirty percent (30%) of participants credited the program and its incentives for their decision to replace their furnace, on average, 2.3 years earlier than planned. This is consistent with the significantly higher proportion of participants than non-participants reporting that their old furnace was still operational at the time of replacement (91% versus 71%).

Satisfaction scores assigned to various program attributes by program participants, based on a five-point satisfaction scale, were generally favourable, with the highest score given to application procedures (4.1) and the lowest score given to size of the rebate (3.7). Trade allies also rated the program positively using the same five-point scale with the highest satisfaction score given to the types and number of furnaces eligible for a rebate (4.2), and the lowest score given to the size of the rebate (3.6).

Participants in the program attributed their awareness of the program to an insert in their Terasen bill (29% of participants), heating or furnace contractor (26%), word of mouth (21%), and direct mail from Terasen (15%). Success in program marketing is often reflected in word of mouth traffic. The Terasen program appears to have successfully achieved this result.

More than half (52%) of Terasen's residential customers who replaced their furnaces during the past three years and did not participate in the Terasen program were simply unaware the program existed. The next most common reasons for not participating (mentioned by anywhere from 17% to 19% of non-participants) included the dollar amount of the rebate (i.e., too small), the hassle factor with applying for the rebate, and the fact that the furnace they chose did not qualify. Ten percent (10%) of non-participants indicated they had applied to the program but had their application rejected.

Participants in Terasen's Heating System Upgrade Program are generally very satisfied with their high efficiency furnace. Ten percent (10%) reported experiencing problems with their new furnace, but only 2% reported having major repairs. A large percentage (71%) of participants reported improvements in the comfort of the home after installing their high efficiency furnace. In contrast, 42% of non-participants reported improvements in home comfort after installing their furnace.

Customers installing VSM-equipped furnaces were significantly more likely than those installing PSC-equipped furnaces to experience an increase in home comfort (68% versus 43% respectively).

Objective 2: Assess program impact on sales of qualifying high-efficiency furnaces (HEF), and variable speed blower motors (VSM), for both participating and non-participating customers.

Information provided by customers and trade allies during the 2004 and 2007 furnace evaluations confirms that the replacement furnace market in British Columbia is moving towards high efficiency furnaces. Trade allies reported that high efficiency furnaces represented 48% of all replacement furnace sales prior to the launch of the most recent program. This share rose to 65% during the program and then declined to 56% after rebates ended in March 2007. VSM-equipped furnaces (either mid- or high efficiency) accounted for 34% of all furnace sales prior to program launch, and 44% following the program conclusion. Trade allies reported the share rising to 56% while the program was in operation.

Forty-three percent (43%) of non-participants reported installing high efficiency furnaces, while 39% installed standard or mid-efficiency furnaces. The remaining 13% of non-participants were not sure of their furnaces' efficiency. The decision not to install a high efficiency model was influenced by first cost, length of payback period, and a general lack of awareness of the relative costs and benefits of high efficiency furnaces. Non-participants were more likely than participants to have annual household incomes of less than $40,000, meaning that the relatively higher cost of a high efficiency furnace (approximately $700 more than a mid-efficiency furnace) was more of a financial hurtle for these households.

The top three reasons for installing a furnace equipped with a variable speed motor were the desire to save electricity (mentioned by 42% of participants), the contractor's recommendation (35%), and the $100 incentive offered by Terasen and its partners (11%). Trade allies were somewhat less likely than customers to attribute the decision to purchase a VSM-equipped furnace to the influence of the rebate (53% versus 57%). The customer-based estimate of free riders was used in the analysis of program impact.

Objective 3: Document and assess program impact on furnace and secondary heating operating behaviours that affect energy use, with particular emphasis on hours of operation.

Four factors influencing furnace operating costs (and savings) were explored in this evaluation – changes in furnace fan operating behaviours, changes in thermostat setting, changes in operating settings, and changes in supplementary heating.

How homeowners use their furnace to heat or cool the house, or to provide ventilation either occasionally or continuously before and after the installation of a VSM-equipped furnace affects the amount of electricity savings realized from the VSM blower motor. The economics of VSM furnace fans depend on operating hours – low operating hours significantly increases the payback period for VSM-equipped furnaces.

This evaluation found that, regardless of the furnace blower type, the number of households using their furnaces to intermittently heat or cool their homes during the heating/cooling seasons declined after installing their new furnace, and a proportion increased their use of the fans to provide continuous heat or cooling during the heating / cooling seasons. The data is inconclusive as to the influence of blower motor choice on behaviours as a significant proportion of households installing furnaces equipped with PSC motors also changed their usage to one of providing more continuous heat or cooling, or to provide ventilation for part of the year . Households that installed VSM-equipped furnaces, however, were more likely to use their fans continuously.

The evaluation found that households who replaced their old PSC-equipped furnaces with a VSM-equipped furnace are comprised of several user types – with no conclusive evidence to suggest that households that used their old furnaces either continuously for heating/ cooling, continuously, or to provide ventilation were predisposed to purchase a VSM-equipped furnace. Instead, energy efficiency, the recommendation of the contractor, and non-energy benefits (e.g., improved comfort, improved air quality via air circulation, pollen filters, etc.) appear to have been more important considerations. Interestingly enough, some households purchasing VSM-equipped furnaces appear to have had unrealistic expectations regarding the electricity savings potential of VSM blowers, as they rated their satisfaction with electricity bill savings from their VSM-equipped furnaces significantly lower than households who purchased PSC-equipped furnaces (3.8 versus 4.2 using a five-point satisfaction scale). Data on furnace fan operating behaviours prior to furnace change out suggest that a significant number of households installing VSM-equipped furnaces tended to use their old furnace fans only intermittently, implying their electricity bill savings would be less significant that those who operated the fans more frequently or continuously.

Changes to Furnace Thermostat Setting

Only 4% of participants and 11% of non-participants increased their thermostat setting to keep their house warmer since installing their new furnace. A significantly greater proportion of participants than non-participants reported turning down the thermostat since replacing their furnace (22% versus 9%). When increases or decreases in temperature (in degrees Celsius) are added to those who reported no change, the net change in indoor temperature for participants was minus 0.6 degrees Celsius compared to plus 0.4 degrees for non-participants. This suggests that participants are maintaining their home temperatures a full degree lower than non-participants, effectively adding to the energy savings attributable to participation in the Terasen program.

Changes to Furnace Operating Settings

Only 5% of participants and 1% of non-participants reported changing one or more operating settings. Participants mentioned changing the furnace to run less frequently, resetting the blower, installing a digital readout, and installing air conditioning. The non-participant reported adjusting the timing of the second stage burner so that it engaged sooner.

Changes to Supplementary Heating

The evaluation found that participants were significantly more likely than non-participants to reduce their use of supplemental heating after replacing their furnace (-16% versus -2%). This suggests that participants' new furnaces are picking up some of the heating load previously met through supplemental sources, most notably the natural gas fireplaces, and to a lesser degree, electric heaters. The transfer of the heating load to the new furnace may result in additional savings as the furnace will be more efficient than the natural gas fireplace. However this may be partially offset if supplementary heating in the pre-furnace change-out period was being used to improve the comfort in the home or parts of the home (e.g., temperature variations between rooms, temperature fluctuations between furnace cycles, etc.). The forthcoming refinement of program savings using a billing analysis will, by its nature, capture these changes in supplementary heating use and the net impact of other changes in heating/cooling use.

Objective 4: Determine the status of market transformation for high efficiency furnaces, and furnaces with variable speed drive blower motors in the British Columbia market.

Market transformation is measured, in part, by changes in market shares of high efficiency products, and declines in the relative price differential of high efficiency units relative to standard efficiency units.

High efficiency furnaces' share of the replacement furnace market rose from 48% prior to program launch to 65% during the program phase, before retreating to 56% after the conclusion of the program. A review of market share data from the past and present evaluations suggests a moderate pullback in the market when no program is in place.

Trade allies reported that 54% of all furnaces replaced between September 2005 and March 2007 were eligible for a rebate from Terasen Gas or its partners.

Trade allies reported that the share of the replacement furnace market represented by VSM-equipped furnaces increased from 34% in the pre-program period to 56% during the program, and then falling to 44% in the post-program period. Terasen's program records indicate that 65% of participants in the heating upgrade program installed a high efficiency furnace equipped with a VSM blower motor. A review of historical market share data suggests that like high efficiency furnaces, VSM market shares seesaw when programs are in effect versus when they are not, although the general trend is upward.

A comparison of equipment and installation costs provided by trade allies surveyed in 2003 and 2007 suggests that equipment prices for all furnace models regardless of efficiency increased over the four-year period, while installation costs either stayed the same or declined somewhat. High efficiency furnaces still cost more on an installed basis than mid- or standard efficiency units. The incremental cost of installing a 75,000 BTU/hour high efficiency furnace compared to a 90,000 BTU/hour mid-efficiency furnace (comparable in output based on efficiency) is $696, down from $877 in 2002, but up somewhat from $608 in 2003.

Objective 5: Develop preliminary estimates of program impact on natural gas sales and carbon dioxide emissions.

Energy savings attributable to Terasen's 2005-07 residential Heating System Upgrade Program, using a net to gross ratio 0.57, include 66.1 terajoules (TJ) in annual savings, plus an additional 22.6 TJ of savings for the first 2.3 years (spillover). Estimated peak day savings are 0.48430 TJ for the first 2.3 years, and then 0.36091 TJ for the remaining years. Assuming an emissions factor of 50 tonnes carbon dioxide per terajoule of energy saved, Terasen is credited with reducing CO^2 emissions from residential furnaces by 4.435 kilotonnes in the first 2.3 years, and 3.305 kilotonnes for subsequent years.

7 Bibliography

Habart 2004, *Impact of Terasen Gas / Energy Star Heating System Upgrade (2003) Program*, Consultant report prepared for Terasen Gas by Habart and Associates Ltd., August 2004.

Pigg 2004, *Electricity Use by New Furnaces*, Scott Pigg, Energy Centre of Wisconsin, commissioned by the State of Wisconsin, Wisconsin Department of Administration, Division of Energy, October 2003.

Appendix A

Customer Survey:
Participants & Non-Participants

Terasen Gas
High Efficiency Furnace Rebate Program Evaluation
Customer Survey

Participant ____ (2006, Jan-Mar 2007)
VSM ___ No VSM ___

Non-Participant ____ (2005, 2006, Jan-Mar 2007)
Rejected Applicant ____
Account Number ____

INTRODUCTION

Hello, my name is __________ from Call Us Info, a marketing research firm. Today I am calling on behalf of Terasen Gas.

The purpose of my call is to collect information that will help Terasen Gas evaluate its efforts to improve the efficiency of home heating systems in BC. I would like to speak to the person responsible for decisions related to your natural gas furnace. Would that person be you?

Yes: CONTINUE
No: ASK TO SPEAK TO THE PERSON RESPONSIBLE FOR DECISIONS RELATED TO THE NATURAL GAS FURNACE. IF NOT AVAILABLE, ASK WHEN IS A BETTER TIME TO CALL BACK. RECORD TIME

Would you be willing to participate in a survey that should take less than 15 minutes of your time?

Yes: CONTINUE
No: ASK IF THERE IS A BETTER TIME TO CALL BACK. RECORD TIME
THANK AND TERMINATE

IF NECESSARY: If respondent would like to verify the legitimacy of this study, they can contact Terasen Gas at 604-576-7000 and advise that they would like to verify a market research study.

PARTICIPANTS:
Did you purchase and install a new natural gas furnace in your home in 2006 or during the first three months of 2007?

IF PARTICIPANT INDICATES NO, THEN RECORD CLIENT ID, THANK AND TERMINATE.

NON PARTICIPANTS:
Did you purchase and install a new natural gas furnace in your home in 2005, 2006, or the first three months of 2007?

Yes: CONTINUE
No: THANK AND TERMINATE

Do you rent or own your home?

Own: CONTINUE

Rent: THANK AND TERMINATE

Q1: Just to confirm, in which month and year did you have the new natural gas furnace installed?

Month _____ Year _____
DK _____

Q2: How old was the old furnace when it was replaced?

Years _____
DK _____

Q2a: Did you receive an incentive from Terasen Gas on the purchase of the new furnace?

Yes _____
No _____
DK _____

IF PARTICIPANT INDICATES NO, THEN RECORD CLIENT ID, THANK AND TERMINATE.

YES: NON PARTICIPANTS FORCE TO PARTICIPANTS

Q3: Was the old furnace still working and producing heat at the time it was replaced?

Yes _____
No _____
DK _____

Now I would like to ask about the efficiency of your new furnace.

- A high efficiency furnace has a minimum efficiency of 90% or more. It is characterized by venting the exhaust through the side of the house rather than through the roof. High efficiency furnaces are usually designated as ENERGY STAR qualified.
- A standard efficiency furnace has an efficiency rating of between 55% and 85%. It is characterized by venting the exhaust through the roof in a flue or chimney.

Q4: Is the new furnace a standard efficiency or a high efficiency unit?

(Note to interviewer, some respondents may refer to a standard efficiency furnace as a mid-efficiency unit). (IF RESPONDENT IS PROGRAM PARTICIPANT THE ANSWER SHOULD AUTOMATICALLY BE HIGH EFFICIENCY. IF NOT PROBE by reviewing the definitions of standard and high efficiency furnace.)

Standard efficiency _____
High efficiency _____
DK _____

Q5: Was the old furnace that was replaced a standard efficiency furnace or a high efficiency furnace?

Standard efficiency _____
High efficiency _____

DK ______

Q6: How satisfied are you with your choice of new furnace? (READ)

Extremely satisfied ____
Very satisfied ____
Somewhat satisfied ____
Not very satisfied ____
Not at all satisfied ____
DK ____

If Extremely / very / somewhat: SKIP TO Q8

Q7: Why are you not satisfied with your choice of furnace?

(SPECIFY) _______

PARTICIPANTS WITH Variable Speed Motors (VSM=1) SKIP TO Q9

Q8: Does your new furnace have a variable speed fan motor? Furnaces equipped with these motors use less electricity but typically cost more than furnaces with standard motors. They can operate over a range of speeds when providing heat or circulating air. (NOTE: standard furnace motors (called PSC motors) typically operate at only one or two fixed speeds).

Yes: ______
No: ______
DK: ______

Yes: CONTINUE WITH Q10a
No: SKIP TO Q11a
DK: SKIP TO Q13

Q9: Unused

IF PARTICIPANT with VSM=1, READ: Our records show that you selected a furnace with a variable speed drive motor.

Q10a: Why did you select a model with a variable speed furnace motor? (DO NOT READ – CHECK ALL THAT APPLY)

It is more energy-efficient ____
It is quieter ____
It can operate through a range of speeds ____
It provides more comfortable ventilation ____
I wanted better indoor air quality ____
It keeps my house warmer ____
It provides even heat ____
I wanted to have continuous ventilation ____
The contractor recommended it ____
I was motivated by the $100 rebate ____
Part of the better furnace I wanted ____

Other (RECORD) ____

Q11a: Prior to installing this furnace, were you aware of, or were you considering, the purchase of, a variable speed furnace motor?

Aware of: _____
Considering purchase: _____
No: _____
DK: _____

NO/NOT AWARE/DK: SKIP TO Q13a

Q11b: How did you become aware of a variable speed furnace motor? (DO NOT READ – CHECK ALL THAT APPLY)

Contractor ____
Terasen Gas ____
BC Hydro ____
Power Smart ____
Other (RECORD) ____

IF Q8=YES/DK/BLANK SKIP TO Q13a

Q12: Why did you <u>not</u> select a furnace model with a variable speed motor (DO NOT READ)?

Was unaware of the variable speed motor ____
Was unaware of the rebate for the variable speed motor ____
Furnace with variable speed motor was too expensive ____
Variable speed motor not available on furnace I chose ____
Contractor did not recommend it ____
Other (RECORD) ____

Q13a: Now we would like to understand how you use your furnace fan.
How did your furnace fan, if any, operate <u>before</u> the furnace change? (READ CHOICES BEFORE GETTING ANSWER)

Intermittently when providing heat ____
Continuously during the heating season ____
Intermittently when providing heat or air conditioning ____
Continuously during the heating / cooling seasons ____
Intermittently to <u>also</u> provide ventilation for part of the year ____
Continuously ____
No furnace fan (boiler) ____
DK ____

IF "Intermittently to also provide ventilation for part of the year"
Q13b: Approximately how many months per year did you operate the fan in this way? RECORD _____

Q13c: How does your furnace fan, if any, operate <u>after</u> the furnace change? (READ CHOICES BEFORE GETTING ANSWER)

Intermittently when providing heat ____
Continuously during the heating season ____
Intermittently when providing heat and air conditioning ____
Continuously during the heating / cooling seasons ____
Intermittently to <u>also</u> provide ventilation for part of the year ____
Continuously ____
No furnace fan (boiler) ____
DK ____

IF "Intermittently to also provide ventilation for part of the year"
Q13d: Approximately how many months per year do you plan to operate the fan in this way?
RECORD ____

Q13e: Thinking of the winter months only, have you set the thermostat to keep your house warmer, cooler, or the same than before the furnace change?

Warmer ____
Cooler ____
Neither (The Same) ____
Too soon to know ____
DK ____

IF "THE SAME" SKIP TO Q13f

Q13e – 1: If warmer/cooler – On average, how many degrees warmer/cooler do you keep your house during the winter compared to before you changed your furnace.(NOTE: CONFIRM UNITS – CELCIUS OR FARHENHEIT)
____° Celsius
____° Fahrenheit

Q13f: Other than adjusting the thermostat, have you changed any operating settings on your furnace since it was installed? (PROMPT: For example: changed when or how long the blower fan operates…)

Yes: _____
No: _____
DK: _____

Q13g: If Yes: What operating settings did you change? ___________________________

Q13h: Why did you make this change? ___________________________

Q14a: Are you familiar with the ENERGY STAR label for natural gas furnaces? Only furnaces that meet a high level of energy efficiency can qualify for ENERGY STAR.

Yes: _____
No: _____
DK: _____

Yes: CONTINUE WITH Q14
No/DK: SKIP TO Q16

Q14b: Was your furnace identified with an ENERGY STAR symbol on the furnace or the furnace brochure?

Yes: _____
No: _____
DK: _____

NON-PARTICIPANTS: SKIP TO Q16

Q15: On a scale of 1 to 5 where 1 is not at all important and 5 is very important, how important is it to you that the Terasen Gas incentive program included products that met the Energy Star high efficiency levels?

1 2 3 4 5 DK

Q16: What was the installed price of the new furnace, including any applicable taxes? (PROMPT IF NECESSARY: AN ESTIMATE IS OK)

Price: $ _____
DK: _____

Q17a: NON-PARTICIPANTS: Were you aware of the Terasen Gas program which offered an incentive for the purchase of a high efficiency ENERGY STAR qualified natural gas furnace?

Yes ____
No ____
DK ____

Yes: CONTINUE WITH Q17a-1
No/DK: SKIP TO Q29

Q17a-1: NON-PARTICIPANTS: Why did you not participate in the Terasen program? (DO NOT READ – CHECK ALL THAT APPLY)

Furnace did not qualify for rebate ____
Had planned to / didn't get around to it ____
Not worth the effort / Didn't want to bother ____
Rebate too small ____
Didn't know how to apply ____
Tried to – rebate application was rejected ____
Contractor was not registered with program ____
Other (SPECIFY) _____________ ____

SKIP ALL REMAINING NON-PARTICIPANTS TO Q29

Now I would like to obtain your opinion on the Terasen Gas incentive program.

Q17b: How did you become aware of the incentive program? (DO NOT READ - CHECK ALL THAT APPLY)

Insert in Terasen Gas bill ____
Direct mail from Terasen Gas ____
Terasen Gas Web site ____
Radio advertisement ____
TV advertisement ____
Newspaper or magazine advertisement ____
Through heating or furnace contractor ____
Word of mouth ____
Natural Resource Canada Web site ____
Trade shows and consumer events ____

Other Websites ____
Other (list) ____

Q18a: What did you like about the promotion?

Like (LIST) ____________________________
DK ____

Q18b: What did you least like about the promotion?

Dislike (LIST)____________________________
DK ____

Q19. Unused

NON-PARTICIPANTS: SKIP TO Q29

Q20: On a scale of one to five, where one is not at all important and five is very important, how important was the Terasen Gas incentive in your choice of a high efficiency furnace?

1 2 3 4 5 DK

ASK Q27 ONLY OF PARTICIPANTS WITH VSM=1 FROM SCREENER

Q27: Our records show that you received an additional incentive for purchasing a high efficiency furnace with a variable speed blower motor. On a scale of one to five, where one is not at all important and five is very important, how important was this additional incentive to your choice of furnace that came with a variable speed blower motor?

1 2 3 4 5 DK

Q28 Unused

Q29: Did you receive a manufacturers' offer or rebate on the purchase of this furnace?
Yes ______
No ______
DK ______

Yes: CONTINUE WITH Q30
No/DK: SKIP TO QUESTION 31

Q30: What was the dollar value of the manufacturers' rebate and offer you received?

Amount $ _____
DK _____

NON-PARTICIPANTS SKIP TO Q36

Q31: On a scale of one to five, where one is not at all satisfied, and five is very satisfied, how satisfied were you with the following aspects of the rebate program? (ROTATE)

Information on the rebate	1 2 3 4 5 DK
Number or type of furnaces eligible for the rebate	1 2 3 4 5 DK
Application procedures to obtain the rebate	1 2 3 4 5 DK
Amount of the rebate	1 2 3 4 5 DK
Information about efficient furnaces	1 2 3 4 5 DK

Q32: Did you call Terasen Gas' customer call center about this program?

Yes ____
No ____
DK ____

NO/ DK: GO TO Q34

Q33: What was the purpose of this call? DO NOT READ, CHECK ALL THAT APPLY?

To clarify my eligibility for the incentive ____
To determine if the furnace was eligible for the rebate(s) ____
To understand the rebate ____
Other (LIST) ________________________________

Q34: Did you replace the furnace earlier than planned because of the availability of the rebate?

Yes ____
No ____
DK ____

Yes: CONTINUE WITH Q35
No/DK: SKIP TO Q36

Q35: How many years earlier than planned did you replace the furnace because of the availability of the rebate?

Years _____
DK _____

Q36: What is the approximate capacity of your new furnace in BTUs per hour?

Record response _____ BTU per hour
DK _____

Q37: We would like to understand how satisfied you are with various aspects of your new furnace. On a scale of one to five, where one is not at all satisfied and five is very satisfied, how satisfied are you with the following? (ROTATE)

The price of your furnace	1 2 3 4 5 DK
The reliability of your furnace	1 2 3 4 5 DK
Natural gas consumption of your furnace	1 2 3 4 5 DK
Ease of installation of your furnace	1 2 3 4 5 DK
After sales service for your furnace	1 2 3 4 5 DK
Amount of your natural gas bill after installing the furnace.	1 2 3 4 5 DK
Amount of your electricity bill after installing the furnace.	1 2 3 4 5 DK

Q38: Have you had any problems with your new furnace?

YES: CONTINUE WITH Q39:
NO: SKIP TO Q40

Q39: What problems have you experienced (DO NOT READ – CHECK ALL THAT APPLY)

Furnace cycles off and on too frequently
Furnace has required major repairs
Difficult to maintain the right temperature
Furnace is too noisy
Furnace has excessive vibration
Furnace produces an uncomfortable draft
Furnace size is too small
OTHER (SPECIFY) ____________

Q40: Since the new furnace was installed, has the comfort level of your house increased, decreased or remained the same?

INCREASED	GO TO Q41
DECREASED	GO TO Q42
REMAINED THE SAME	GO TO Q43

Q41: In what way has the comfort increased (DO NOT READ – CHECK ALL THAT APPLY)?

More even temperatures between the rooms ____
Rooms that were previously cold are warmer ____
Indoor air quality has improved ____
House more comfortable ____
House warmer now ____
Quiet operation of fan / less noise ____
Other (RECORD) ____________________________

GO TO Q43

Q42: In what way has the comfort decreased (DO NOT READ – CHECK ALL THAT APPLY)?

Noise level increased ____
Cool drafts ____
Other (RECORD ______________________________

Q43: On a scale of 1 to 5, where 1 is not at all important and 5 is very important, please rate the following attributes in terms of their influence on your choice of your home heating system. (ROTATE)

Comfort in your home	1 2 3 4 5 DK
Indoor air quality	1 2 3 4 5 DK
Energy efficiency	1 2 3 4 5 DK
Initial cost of the system	1 2 3 4 5 DK
Operating cost of the system (ie: fuel cost)	1 2 3 4 5 DK
Both initial cost and operating costs	1 2 3 4 5 DK

Q44-46 Unused

Q47: Other than the furnace, does your house have an "other" or supplementary source of heating?

Yes ______
No ______
DK ______

No / DK GO TO Q51:

Q48: What heating fuel is used for the "other" or supplementary heating? (CHECK ALL THAT APPLY)

Natural gas ____
Electricity ____
Propane ____
Wood ____
Oil ____

Q48a: What space heating method is used for the "other" or supplementary heating? (CHECK ALL THAT APPLY)

Electric baseboard heaters ____
Portable electric heaters ____
Heat pump ____
Fireplace ____
Wood stove ____
Central forced air furnace ____
Hot water baseboards ____
Hot water in floor radiant ____
Radiant electric cables ____
Natural gas wall heater ____
Other (LIST) ____

Q49: Has your use of the supplementary heating increased, decreased or remained the same since the installation of the new furnace?

Increased:	GO TO Q50a
Decreased:	GO TO Q50b
Remained the same:	GO TO Q51
DK:	GO TO Q51

Q50a: By about how much has your use of the supplementary heating increased? (READ)

0 – 24%	____
25 – 49%	____
50 – 74%	____
75 – 100%	____
DK	____

GO TO: Q51

Q50b: By about how much has your use of the supplementary heating decreased? (READ)

0 – 24%	____
25 – 49%	____
50 – 74%	____
75 – 100%	____
DK	____

Q51: In the past two years (NON-PARTICIPANTS READ 3 years) have you made any significant changes to your house that would affect natural gas usage?

YES: Go to Q51a
NO: Go to Q52

Q51a: What are the changes that you have made to your house? (DO NOT READ – CHECK ALL THAT APPLY)

Addition to the size of the house	____	
If addition: Approximately how big was the addition	___sq ft	
		___sq meters
Added natural gas furnace as the main heat source for house	____	
Added electric heat pump		____
Removed electric heat pump		____
Installed additional ceiling or wall insulation		____
Caulked or weather stripped drafty exterior surfaces		____
Installed new double or triple glazed windows	____	
Installed new low E windows		____
Installed a new high efficiency hot water heater	____	
Other (SPECIFY)		____

The final questions are for classification purposes only and are completely confidential, as are all your answers.

Q52: What type of home do you live in?

Single detached ______
Semi-detached (duplex) ______
Apartment/condominium ______
Row/townhouse ______
Mobile home or other ______
DK ______

Q53: How old is your home?

Years ______
DK ______

Q54: What is the approximate heated area of your home in square feet or square meters?

Square feet ______
Square meters ______
DK ______

Q55: Do you use natural gas for any of the following ?
READ – IF NOT APPLICABLE RECORD AS "NO"

Main space heating Yes/No/DK
Secondary space heating Yes/No/DK
Fireplace insert Yes/No/DK
Water heating Yes/No/DK
Clothes drying Yes/No/DK
Indoor pool heating Yes/No/DK
Outdoor pool heating Yes/No/DK
Hot tub Yes/No/DK
Cooking Yes/No/DK
Barbeque Yes/No/DK
Patio heater Yes/No/DK

Q56: Into which of the following age categories do you fit? (READ CATEGORIES)

Less than 19 years ______
19-24 years ______
25-34 years ______
35-44 years ______
45-54 years ______
55-64 years ______
65 years and older ______
Prefer not to answer ______

Q57: What is your marital status? (READ CATEGORIES)

Single _______
Married/common law _______

Divorced/separated ______
Widowed ______
Prefer not to answer ______

Q58: How many people, including yourself, are currently living in your household (please include any boarders or renters who do not have a separate natural gas account)?

_____ number

Q59: Please indicate the number of occupants by age categories. (READ CATEGORIES)

0-18 years _____
19-24 years _____
25-34 years _____
35-44 years _____
45-54 years _____
55-64 years _____
65 years and older _____
Prefer not to answer _____

Q60: What is the highest level of education you have completed? (READ CATEGORIES)

Some high school _____
Completed high school _____
Some university/college _____
Completed university/college _____
Some trade/technical school _____
Completed trade/technical school _____
Post graduate _____
Prefer not to answer _____

Q61: What was your total annual household income before taxes in 2006? (READ CATEGORIES)

Less than $20,000 _____
$20,000 to $39,999 _____
$40,000 to $59,999 _____
$60,000 to $79,999 _____
$80,000 to $99,999 _____
$100,000 to $124,999 _____
Over $125,000 _____
Prefer not to answer _____

Q62: What are the first three digits of your postal code?

Response __ __ ___
DK _____

Q63: In order to better understand how customers use natural gas, we would like to link your survey responses to your natural gas usage information. This information will be used only for statistical information and will not identify you as an individual. Do we have your permission to link your survey responses to your natural gas usage data?

Yes ____
No ____
DK ____

PROMPT IF NECESSARY: THE OBJECTIVE OF THIS PROJECT IS TO ASSIST TERASEN GAS IN DETERMINING THE ACTUAL REDUCTION IN NATURAL GAS USAGE ASSOCIATED WITH EFFICIENT FURNACES. THIS IS DONE BY COMPARING YOUR NATURAL GAS CONSUMPTION BEFORE AND AFTER THE INSTALLATION OF THE EFFICIENT FURNACE.

Terasen Gas, and Call Us would like to thank you for your help and assistance.

Appendix B

Trade Ally Survey

Furnace Dealers, Contractors, Installers

Terasen Gas
High Efficiency Furnace Rebate Program Evaluation
Trade Ally Survey

INTRODUCTION

Hello, my name is __________ from Call Us Info, a market research firm. Today I am calling on behalf of Terasen Gas. I would like to speak to the person responsible for residential furnace sales and installation with your firm.

Available: CONTINUE
Not available: ASK WHEN IS A BETTER TIME TO CALL BACK. RECORD TIME.

The purpose of my call is to collect information that will help Terasen Gas improve the efficiency of home heating systems in BC. We will use this information to better understand the impact of more efficient furnaces on natural gas consumption in B.C. and the effectiveness of our promotion programs. Would you be willing to participate in a survey that will take less than 15 minutes of your time?

Yes: CONTINUE
No: ASK IF THERE IS A BETTER TIME TO CALL BACK. RECORD TIME.

IF NECESSARY: If respondent would like to verify the legitimacy of this study, they can contact Terasen Gas at 604-576-7000 and advise that they would like to verify a market research study.

I understand that your firm provides contracting and installation services for replacement natural gas furnaces in BC. Is that correct?

Yes: CONTINUE
No: SEEK CLARIFICATION AND CONTINUE IF FIRM PROVIDES EITHER CONTRACTING OR INSTALLATION SERVICES FOR NATURAL GAS FURNACES. IF NOT, THANK AND TERMINATE

Q1: About what percentage of your furnace sales and installations involve new residential dwellings and what percentage involves replacement furnaces?

New dwellings _____%
Replacements _____%
DK _____

Q2: We are interested in understanding the role of high efficiency furnaces in the market in BC and the impact of Terasen Gas' High Efficiency Furnace program. High efficiency furnaces have a AFUE rating of 90% or better. Terasen's furnace program ran from October 2005 to the end of March 2007.

About what percentage of your replacement furnace sales and installations were high efficiency before, during and since the program terminated at the end of March 2007? (PROBE: IF THE RESPONDENT SAYS "DON'T KNOW" INDICATE THAT AN ESTIMATE IS ALL WE ARE LOOKING FOR)

Before Program _____%
During Program_____%
After Program _____%
DK _____

Q3: We are also interested in the impact of the program on the sale of furnaces with variable speed blower motors. These motors may also be referred to as "ECM" motors. About what percentage of your furnace replacement sales and installations before, during and after the Terasen program included variable speed blower motors? (PROBE: IF THE RESPONDENT SAYS "DON'T KNOW" INDICATE THAT AN ESTIMATE IS ALL WE ARE LOOKING FOR)

Before Program _____%
During Program_____%
After Program _____%
DK _____

Q4: Unused

Now we would like to understand if the Terasen Gas incentive program encouraged customers to replace furnaces earlier than they would otherwise do so.

Q5a: About what percentage of the furnaces you replaced between October 2005 and March 2007 were eligible for a rebate from Terasen Gas or its partners?

Percentage ____ %
DK ____

Q6: What was the average remaining length of life of those furnaces that were replaced while still operational?

Years _____
DK _____

Q7: Do you routinely do a heat loss calculation when installing a replacement furnace?

Yes _____
No _____

No: SKIP TO Q9

Q8: What percentage of the time does doing the heating loss calculation lead to the choice of a smaller capacity furnace than you would have recommended if the heat loss calculation had not been done?

Percentage _____
DK _____

Q9: What would be a typical equipment price excluding taxes for a 90,000 BTU/hr input mid-efficiency natural gas replacement furnace?

Price ______

DK/NR ______
(NOTE TO INTERVIEWER, IF RESPONDENT DOES NOT HAVE A 90,000 BTU/HR INPUT PRODUCT, PLEASE ASK FOR THE INFORMATION REGARDING THE NEAREST SIZED FURNACE.)

Q10: What would be a typical installed price excluding taxes for a 90,000 BTU/hr input mid-efficiency natural gas replacement furnace?

Price ______
DK ______

Q11: What would be a typical equipment price excluding taxes for a 90,000 BTU/hr input high efficiency natural gas replacement furnace?

Price ______
DK/NR ______

Q12: What would be a typical installed price excluding taxes for a 90,000 BTU/hr input high efficiency natural gas replacement furnace?

Price ______
DK ______

Q13: What would be a typical equipment price excluding taxes for a 75,000 BTU/hr input high efficiency natural gas replacement furnace?

Price ______
DK/NR ______

Q14: What would be a typical installed price excluding taxes for a 75,000 BTU/hr input high efficiency natural gas replacement furnace?

Price ______
DK ______

Now I would like to obtain your opinion on the Terasen Gas incentive program which supported the installation of high efficiency furnaces and high efficiency variable speed fan motors. The program offered rebates for high efficiency furnaces from October 2005 to March 2007.

Q15: On a scale of one to five, where one is not at all satisfied, and five is very satisfied, how satisfied were you with the following aspects of the rebate program? (ROTATE)

Information on the rebate	1 2 3 4 5 DK
Types or numbers of furnaces eligible for the rebate	1 2 3 4 5 DK
Application procedures to obtain the rebate	1 2 3 4 5 DK
Amount of the rebate	1 2 3 4 5 DK

Q16: On a scale of one to five, where one is not at all important and five is very important, how important was the rebate in your customers' choice of furnace efficiency?

1 2 3 4 5 DK

Q17: Unused
Q18: Unused
Q19: Unused

Q20: The program included an additional incentive for the purchase of a furnace with an energy-efficient variable speed blower motor. On a scale of one to five, where one is not at all important and five is very important, how important was the $ 100 incentive in your customers' choice of furnace blower motor efficiency?

1 2 3 4 5 DK

Q21: Unused

Q22: Unused

Q23: Of the furnace models you sold while the program was in operation, what percentage had:
Single speed PSC blower motors ____%
Multi-speed PSC blower motors ____%
Variable speed blower motors ____%
DK ____

PROMPT IF NECESSARY: A PSC OR PERMANENT SPLIT CAPACITOR MOTOR REFERS TO A BLOWER MOTOR THAT TYPICALLY OPERATES AT ONE OR TWO SPEEDS BUT IS LESS EFFICIENT THAN VARIABLE SPEED MOTORS THAT CAN OPERATE THROUGH A BROAD RANGE OF SPEEDS. FURNACES EQUIPPED WITH PSC MOTORS ARE LESS EXPENSIVE THAN THOSE EQUIPPED WITH VARIABLE SPEED MOTORS.

PROMPT IF NECESSARY: THE TERASEN FURNACE PROGRAM WAS IN EFFECT FROM OCTOBER 2005 TO MARCH 2007.

Q24a: What percentage of the standard (mid) efficiency furnaces you sold during the program period had a variable speed motor?
____%

Q24b: What percentage of the high efficiency furnaces you sold during the program period had a variable speed motor?
____%

Q24d: What were the reasons why customers purchased a furnace with a variable speed blower motor? (DO NOT READ - SPECIFY ALL THAT APPLY)

It uses less electricity ____
It is quieter ____
It provides more comfortable ventilation ____
It can operate through a range of speeds ____
The $ 100 rebate ____
Customer wanted continuous ventilation___ ____
Customer wanted the "best" furnace ____
Contractor / sales person sold the feature ____
Came with the furnace that was ordered _______
Other (RECORD) ______________________

Q25: Are you familiar with the ENERGY STAR label for natural gas furnaces:

Yes:	_____
No:	_____
DK:	_____

NO / DK: GO TO Q29.

Q26: Do you recommend ENERGY STAR natural gas furnaces to your customers?

Yes	_____
No	_____
Sometimes/depends on the customer	_____
DK	_____

Q27: Unused

Q28: Unused

Next we would like to understand your views of high efficiency furnaces.

Q29: Do you believe that high efficiency furnaces are the best choice for your customers?

Yes	_____
No	_____
Sometimes/depends on the customer	_____
DK	_____

Yes, no, sometimes/depends on the customer: CONTINUE WITH Q30
DK: SKIP TO Q31

Q30: Why do you say this?

Record response _____

Q31: Do you recommend variable speed blower motors to your customers?

Yes	_____
No	_____
Sometimes/depends on customer	_____
DK	_____

Yes, no, sometimes/depends on the customer: CONTINUE WITH Q32
DK: SKIP TO Q33

Q32: Why do you say this?

Record response _____

Q33: Do you recommend two-stage mid-efficiency furnaces to your customers as a preferred option to a high efficiency furnace?

Yes ______
No ______
Sometimes/depends on customer ______
DK ______

Yes, no, sometimes/depends on the customer: CONTINUE WITH Q34
DK: SKIP TO Q35

Q34: Why do you say this?

Record response ______

The next few questions are to help Terasen understand how their rebate program may have influenced how households operate their furnaces.

Q35: In what percentage of the furnaces that you replaced did the ventilation fans run:
(READ THE CATEGORIES BEFORE OBTAINING RESPONSES. ANSWERS SHOULD SUM TO 100%. IF NOT, REVIEW THE RESPONSES WITH THE RESPONDENT AND ADJUST ACCORDINGINGLY)

Intermittently when providing heat ____%
Continuously during the heating season ____%
Intermittently when providing heat and air conditioning ____%
Continuously during the heating and cooling seasons ____%
Intermittently to <u>also</u> provide ventilation for part of the year ____%
Continuously ____%
DK ______

Q36: In what percentage of <u>all your installations</u> of furnaces with PSC motors do the ventilation fans run: (READ THE CATEGORIES BEFORE OBTAINING RESPONSES. ANSWERS SHOULD SUM TO 100%. IF NOT, REVIEW THE RESPONSES WITH THE RESPONDENT AND ADJUST ACCORDINGINGLY)

Intermittently when providing heat ____%
Continuously during the heating season ____%
Intermittently when providing heat and air conditioning ____%
Continuously during the heating and cooling seasons ____%
Intermittently to <u>also</u> provide ventilation for part of the year ____%
Continuously ____%
DK ______

Q38: Thinking now of only those furnaces with variable speed motors, in what percentage of <u>all your installations</u> of furnaces with <u>variable speed motors</u> do the ventilation fans run: (READ THE CATEGORIES BEFORE OBTAINING RESPONSES. ANSWERS SHOULD SUM TO 100%. IF NOT, REVIEW THE RESPONSES WITH THE RESPONDENT AND ADJUST ACCORDINGINGLY)

Intermittently when providing heat ____%
Continuously during the heating season ____%
Intermittently when providing heat and air conditioning ____%
Continuously during the heating and cooling seasons ____%
Intermittently to <u>also</u> provide ventilation for part of the year ____%
Continuously ____%
DK _____

Q39: Do you believe that your customers have enough information to make an informed decision on their <u>choice of furnace efficiency</u>?

Yes _____
No _____
Sometimes/depends on customer _____
DK _____

No, sometimes/depends on the customer: CONTINUE WITH Q40
Yes / DK: SKIP TO Q41

Q40: What information are they missing when making a decision on the choice of furnace efficiency?
Record answer: __________

Q41: Do you believe that your customers have enough information to make an informed decision on whether to purchase a furnace with a PSC or variable speed furnace motor?

Yes _____
No _____
Sometimes/depends on customer _____
DK _____

No, sometimes/depends on the customer: CONTINUE WITH Q42
Yes / DK: SKIP TO Q43

Q42: What information are they missing when making a decision on the choice of furnace blower motor?
Record answer: __________

Q43 – Q47: Unused

Finally we have a few questions to help us classify the data.

Q48: How many employees are there in your firm?

Number _____
DK/NR _____

Q49: Which of the following categorization best describes your business?

Furnace Dealer and Heating Contractor ____

Independent Heating Contractor ____
Gas fitter ____
Other (RECORD) ____

Q50. Do you have any suggestions on how consumers could be encouraged to install higher efficiency rather than mid-efficiency furnaces?

Record answer _____

Q51: Do you have any suggestions on how consumers could be encouraged to install variable speed furnace blower motors rather than the less efficient PSC motors?

Record answer _____

Terasen Gas and Call Us would like to thank you for your help and for your assistance.

Appendix C

Preparation of Survey Samples

Appendix C
Preparation of Survey Samples

C.1 Survey Groups

Survey samples were developed for four different survey groups:

- Program participants
- Program non-participants
- Program declined non-participants (alternative source of non-participating customers)
- Trade allies (furnace dealers, contractors, installers)

C.1.1 Participants, Non-Participants, & Declined

Participant and declined lists were assembled from program records for the 2006-07. The list of non-participants was created by sampling the Energy Extracts provided by ABSU. The non-participant list was screened for customers showing up the 2005-2007 participant or declined lists, or on the 2002-2004 participant lists provided by ABSU. The regional breakdown of the non-participants matches that of the participants. Customers in the declined lists represented customers that submitted a rebate application but were denied due to furnace ineligibility, self-installation, or other reason. This list was prepared as an alternative list of non-participants if the non-participant sample was exhausted prior to achieving quota.

C.1.1.1 Pre-Weather Normalization Filters

For the participants and declined list, consumption information was collected based on the most recent 12 month period prior to the installation. For the non-participants, 36 months of consumption up to March 31, 2007 was obtained.

To improve the likelihood of a non-participant having replaced their furnace in the past three years, it was decided to remove any accounts where the premise was younger than 15 years (i.e., the average life of a furnace is approximately 15 years). This step was possible for the LML region but due to issues with the SupplyReqDate field in the Energy Extracts, only premises less than eight years old could be excluded in the other regions.

C.1.1.2 Weather Normalization & Other Billing History Filters

Using the bi-monthly meter reads (and associated consumption) and weather data, the average daily consumption per meter read, and the average daily HDD13 and HDD18 for that same period, are determined. The following regression model (1) was then run:

(1) Average Daily Consumption = $\beta_0 + (\beta_1 \text{ X } HDD_{13}) + (\beta_2 \text{ X } HDD_{18})$

The total HDD_{13}'s and HDD_{18}'s during a "normal" year (basically the average of the past ten years) were determined. Normalized annual consumption was then calculated using equation (2):

(2) Normal Consumption = $(365 \text{ X } \beta_0) + (\text{Total } HDD_{13}\text{'s X } \beta_1) + (\text{Total } HDD_{18}\text{'s X } \beta_2)$

Finally, the following elimination criteria (i.e., screens) were applied to generate finalized lists:

1. Remove all customers not in the same premise for at least one year prior to and after the installation date.
2. Remove all customers where the regressions give an R-Square value below 0.75. This ensures the remaining customers results reflect a good fit with the data, and their consumption is predictable.
3. Remove those customers where the heat slope coefficients (HDD_{13}, HDD_{18}) are negative. It is reasonable to expect that customers will consume more gas when the heating degree days increase. Negative heat slope coefficients suggests that consumption declines as heating degree days increase.
4. Remove all customers with annual consumption less than 30GJ. Customers with annual consumption less than 30GJ are unlikely to be using natural gas for space heating.
5. Remove customers where the EDF (Error Degrees of Freedom) is less than three. In effect, this removes customers with less than five meter reads.
6. Remove all customers with suspect meter reads. These include meter reads where the transaction period refers back to a date prior to the last read date output (i.e., the read date less the corresponding read days is before the last read date).
7. Remove all customers where consumption for one read date or more is zero. There should be at least six meter reads per a year's worth of consumption. One year of consumptions is the minimum acceptable time.
8. Remove all customers where the weather effect is more than two standard deviations away from the average weather effect. The weather effect is defined as:

   Weather Effect = (Normal Consumption – Actual Consumption) / Actual Consumption

   Since 96% of all data is within two standard deviations of the mean, this eliminates those with abnormally large weather effects (i.e., outliers).

C.2 Trade Allies

A list of 640 contractors who participated in the Heating System Upgrade Program was generated by matching contractor registration numbers from the application with the list of contractors registered with the British Columbia Safety Authority (BCSA). Access to this list was allowed under the Safety Standards Act Sec 21.

C.3 Summary

Exhibit 98 summarizes the starting sample sizes for the customer and trade ally surveys.

Exhibit 98: Starting Sample and Quota

Survey Group	Starting Sample	Survey Quota (n)
Trade Allies	640	50
Participants	4,268	100
Non-participants	33,277	100
Declined List	581	n/a

Appendix D

Expanded Tabulations

Appendix D
Expanded Tabulations

Exhibit D1: Customer Satisfaction with Various Program Components

	Information on the Rebate	Number or Types of Furnaces Available for Rebate	Application Procedures to Obtain the Rebate	Amount of the Rebate	Information about Efficient Furnaces
Base (n)	*200*	*100*	*100*	*40*	*120*
Not at all Satisfied (1)	2%	4%	1%	2%	3%
Not Very Satisfied (2)	4%	4%	5%	12%	4%
Somewhat Satisfied (3)	17%	18%	17%	20%	22%
Very Satisfied (4)	37%	24%	26%	30%	38%
Extremely Satisfied (5)	31%	27%	41%	26%	26%
DK/NR*	9%	23%	10%	10%	7%
Total	**100%**	**100%**	**100%**	**100%**	**100%**
Not Very or Not at all Satisfied	7%	10%	7%	16%	8%
Extremely or Very Satisfied	75%	66%	74%	62%	69%
Mean	***4.0***	***3.9***	***4.1***	***3.7***	***3.9***

Totals may not sum due to rounding
** excluded from calculation of mean satisfaction*

Exhibit D2: Customer Satisfaction with Various Furnace Attributes
Price of the Furnace

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Not at all Satisfied (1)	1%	1%	-	-	1%	-
Not Very Satisfied (2)	6%	5%	7%	13%	5%	3%
Somewhat Satisfied (3)	20%	26%	14%	10%	23%	20%
Very Satisfied (4)	38%	38%	38%	45%	38%	30%
Extremely Satisfied (5)	28%	28%	28%	25%	28%	30%
DK/NR*	8%	2%	13%	8%	4%	18%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Not Very or Not at all Satisfied	7%	6%	7%	13%	6%	3%
Extremely or Very Satisfied	66%	66%	66%	70%	67%	60%
Mean	***3.9***	***3.9***	***4.0***	***3.9***	***3.9***	***4.1***

Totals may not sum due to rounding
** excluded from calculation of mean satisfaction*

Exhibit D3: Customer Satisfaction with Various Furnace Attributes
Reliability of Your Furnace

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Not at all Satisfied (1)	1%	1%	-	-	1%	-
Not Very Satisfied (2)	2%	-	3%	8%	-	-
Somewhat Satisfied (3)	2%	1%	3%	3%	2%	3%
Very Satisfied (4)	27%	24%	30%	35%	23%	30%
Extremely Satisfied (5)	63%	66%	60%	55%	66%	63%
DK/NR*	6%	8%	4%	-	8%	5%
Total	**100%**	**100%**	**100%**	**100%**	**99%**	**100%**
Not Very or Not at all Satisfied	2%	1%	3%	8%	1%	0%
Extremely or Very Satisfied	90%	90%	90%	90%	89%	93%
Mean	***4.6***	***4.7***	***4.5***	***4.4***	***4.7***	***4.6***

Totals may not sum due to rounding
** excluded from calculation of mean satisfaction*

Exhibit D4: Customer Satisfaction with Various Furnace Attributes
Natural Gas Consumption of Your Furnace

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Not at all Satisfied (1)	2%	3%	1%	-	3%	-
Not Very Satisfied (2)	2%	3%	1%	3%	2%	3%
Somewhat Satisfied (3)	13%	13%	12%	10%	14%	10%
Very Satisfied (4)	37%	32%	42%	50%	30%	45%
Extremely Satisfied (5)	36%	39%	33%	25%	40%	35%
DK/NR*	11%	10%	11%	13%	11%	8%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Not Very or Not at all Satisfied	4%	6%	2%	3%	5%	3%
Extremely or Very Satisfied	73%	71%	75%	75%	70%	80%
Mean	***4.2***	***4.1***	***4.2***	***4.1***	***4.1***	***4.2***

Totals may not sum due to rounding
** excluded from calculation of mean satisfaction*

**Exhibit D5: Customer Satisfaction with Various Furnace Attributes
Ease of Installation**

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Not at all Satisfied (1)	2%	1%	2%	-	2%	3%
Not Very Satisfied (2)	3%	3%	3%	3%	2%	8%
Somewhat Satisfied (3)	5%	5%	5%	8%	4%	5%
Very Satisfied (4)	28%	27%	28%	35%	29%	15%
Extremely Satisfied (5)	48%	49%	47%	50%	48%	48%
DK/NR*	15%	15%	15%	5%	16%	23%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Not Very or Not at all Satisfied	5%	4%	5%	3%	3%	10%
Extremely or Very Satisfied	76%	76%	75%	85%	77%	63%
Mean	***4.4***	***4.4***	***4.4***	***4.4***	***4.4***	***4.3***

Totals may not sum due to rounding
** excluded from calculation of mean satisfaction*

**Exhibit D6: Customer Satisfaction with Various Furnace Attributes
After Sales Service**

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Not at all Satisfied (1)	3%	3%	2%	3%	3%	-
Not Very Satisfied (2)	2%	2%	2%	-	3%	3%
Somewhat Satisfied (3)	9%	12%	6%	10%	8%	10%
Very Satisfied (4)	22%	17%	27%	38%	20%	13%
Extremely Satisfied (5)	39%	39%	39%	38%	38%	43%
DK/NR*	26%	27%	24%	13%	28%	33%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Not Very or Not at all Satisfied	5%	5%	4%	3%	6%	3%
Extremely or Very Satisfied	61%	56%	66%	75%	58%	55%
Mean	***4.2***	***4.2***	***4.3***	***4.2***	***4.2***	***4.4***

Totals may not sum due to rounding
** excluded from calculation of mean satisfaction*

Exhibit D7: Customer Satisfaction with Various Furnace Attributes
Amount of Your Natural Gas Bill after Installing the Furnace

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Not at all Satisfied (1)	2%	3%	1%	3%	3%	-
Not Very Satisfied (2)	2%	3%	1%	3%	2%	3%
Somewhat Satisfied (3)	23%	26%	20%	28%	23%	20%
Very Satisfied (4)	26%	22%	29%	23%	24%	33%
Extremely Satisfied (5)	31%	30%	31%	23%	33%	30%
DK/NR*	17%	16%	18%	23%	16%	15%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Not Very or Not at all Satisfied	4%	6%	2%	5%	4%	3%
Extremely or Very Satisfied	56%	52%	60%	45%	58%	63%
Mean	***4.0***	***3.9***	***4.1***	***3.8***	***4.0***	***4.1***

Totals may not sum due to rounding
** excluded from calculation of mean satisfaction*

Exhibit D8: Customer Satisfaction with Various Furnace Attributes
Amount of Your Electricity Bill after Installing Your Furnace

	Total	Participants	Non-Participants	PSC	VSM	Unknown Blower Motor Type
Base (n)	*200*	*100*	*100*	*40*	*120*	*40*
Not at all Satisfied (1)	2%	3%	-	-	3%	-
Not Very Satisfied (2)	5%	3%	6%	5%	5%	3%
Somewhat Satisfied (3)	18%	23%	13%	10%	23%	10%
Very Satisfied (4)	25%	13%	36%	30%	19%	35%
Extremely Satisfied (5)	27%	28%	25%	35%	24%	25%
DK/NR*	25%	30%	20%	20%	26%	28%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Not Very or Not at all Satisfied	6%	6%	6%	5%	8%	3%
Extremely or Very Satisfied	51%	41%	61%	65%	43%	60%
Mean	***3.9***	***3.9***	***4.0***	***4.2***	***3.8***	***4.1***

Totals may not sum due to rounding
** excluded from calculation of mean satisfaction*

Exhibit D9: Importance of Attributes that Influenced Choice of Home Heating System Comfort in Your Home

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Not at all Important (1)	1%	1%	-
(2)	2%	2%	2%
(3)	12%	12%	12%
(4)	32%	31%	33%
Very Important (5)	50%	51%	49%
DK/NR*	4%	3%	4%
Total	**100%**	**100%**	**100%**
Not important (1 or 2)	3%	3%	2%
Important (4 or 5)	82%	82%	82%
Mean	***4.3***	***4.3***	***4.3***

Totals may not sum due to rounding
** excluded from calculation of mean importance*

Exhibit D10: Importance of Attributes that Influenced Choice of Home Heating System Indoor Air Quality

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Not at all Important (1)	1%	2%	-
(2)	2%	1%	2%
(3)	15%	17%	12%
(4)	33%	29%	36%
Very Important (5)	42%	38%	45%
DK/NR*	9%	13%	5%
Total	**100%**	**100%**	**100%**
Not important (1 or 2)	3%	3%	2%
Important (4 or 5)	74%	67%	81%
Mean	***4.2***	***4.1***	***4.3***

Totals may not sum due to rounding
** excluded from calculation of mean importance*

Exhibit D11: Importance of Attributes that Influenced Choice of Home Heating System Energy Efficiency

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Not at all Important (1)	1%	-	1%
(2)	1%	-	1%
(3)	9%	6%	12%
(4)	31%	29%	32%
Very Important (5)	50%	56%	43%
DK/NR*	10%	9%	11%
Total	**100%**	**100%**	**100%**
Not important (1 or 2)	1%	0%	2%
Important (4 or 5)	80%	85%	75%
Mean	***4.4***	***4.5***	***4.3***

Totals may not sum due to rounding
** excluded from calculation of mean importance*

Exhibit D12: Importance of Attributes that Influenced Choice of Home Heating System Initial Cost of the System

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Not at all Important (1)	2%	3%	1%
(2)	4%	3%	5%
(3)	20%	22%	17%
(4)	36%	40%	31%
Very Important (5)	30%	23%	36%
DK/NR*	10%	9%	10%
Total	**100%**	**100%**	**100%**
Not important (1 or 2)	6%	6%	6%
Important (4 or 5)	65%	63%	67%
Mean	***4.0***	***3.8***	***4.1***

Totals may not sum due to rounding
** excluded from calculation of mean importance*

Exhibit D13: Importance of Attributes that Influenced Choice of Home Heating System Operating Cost of the System (i.e., Fuel Cost)

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Not at all Important (1)	1%	2%	-
(2)	3%	2%	4%
(3)	15%	17%	12%
(4)	28%	23%	33%
Very Important (5)	40%	41%	38%
DK/NR*	14%	15%	13%
Total	**100%**	**100%**	**100%**
Not important (1 or 2)	4%	4%	4%
Important (4 or 5)	68%	64%	71%
Mean	***4.2***	***4.2***	***4.2***

Totals may not sum due to rounding
** excluded from calculation of mean importance*

Exhibit D14: Importance of Attributes that Influenced Choice of Home Heating System Both Initial Cost and Operating Costs

	Total	Participants	Non-Participants
Base (n)	*200*	*100*	*100*
Not at all Important (1)	1%	1%	-
(2)	5%	5%	4%
(3)	17%	17%	17%
(4)	33%	35%	31%
Very Important (5)	33%	29%	37%
DK/NR*	12%	13%	11%
Total	**100%**	**100%**	**100%**
Not important (1 or 2)	5%	6%	4%
Important (4 or 5)	66%	64%	68%
Mean	***4.1***	***4.0***	***4.1***

Totals may not sum due to rounding
** excluded from calculation of mean importance*

Exhibit D15: Trade Ally Satisfaction with Various Aspects of the Terasen Rebate Program

	Information on the Rebate	Types or Numbers of Furnaces Eligible for Rebate	Application Procedures to Obtain the Rebate	Amount of the Rebate
Base (n)	*200*	*100*	*100*	*40*
Not at all Satisfied (1)	10%	2%	4%	10%
Not Very Satisfied (2)	6%	4%	8%	8%
Somewhat Satisfied (3)	16%	16%	8%	22%
Very Satisfied (4)	32%	28%	24%	26%
Extremely Satisfied (5)	34%	46%	48%	30%
DK/NR*	2%	4%	8%	4%
Total	**100%**	**100%**	**100%**	**100%**
Not Very or Not at all Satisfied	16%	6%	12%	18%
Extremely or Very Satisfied	66%	74%	72%	56%
Mean	***3.8***	***4.2***	***4.1***	***3.6***

Totals may not sum due to rounding
** excluded from calculation of mean satisfaction*

Attachment 71.4

Ontario Energy Board

Commission de l’Énergie de l’Ontario

Ontario

EB-2006-0021

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF a generic proceeding initiated by the Ontario Energy Board to address a number of current and common issues related to demand side management activities for natural gas utilities.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

August 25, 2006

EXECUTIVE SUMMARY

The Ontario Energy Board (the "Board") determined the original regulatory framework for gas utility sponsored Demand Side Management ("DSM") programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, Union Gas Limited ("Union") and Enbridge Gas Distribution Inc, ("EGD") have been filing DSM plans in response to the directives of the Board in the EBO 169-III Report.

In the Board's EB-2005-0001 decision dealing with EGD's 2006 rates, the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities – this decision. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act. The Board's findings in this decision, therefore, are orders of the Board pursuant to section 36 of the Act.

At the beginning of the oral hearing the Board was presented several documents which segmented the issues list into four categories. The categories consisted of a list of completely settled issues, a list of partially settled issues to which most intervenors and the utilities agreed, a list of partially settled issues to which all intervenors agreed with the exception of the utilities, and, a list of completely unsettled issues. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The Board's decision deals with a large number of issues relating to DSM. Generally, a rules-based and framework approach has been established where appropriate and practical. Below is a list of the broader matters that have been decided.

- A three-year term for the first DSM plan
- Processes for adjustments during the term of the plan
- Formulaic approaches for DSM targets, budgets, and utility incentives
- Determination of how costs should be allocated to rate classes
- A framework for determining savings
- A framework and process for evaluation and audit
- The role of the gas utilities in electric Conservation and Demand Management activities and initiatives

The Board will issue a Procedural Order to commence the next phase dealing with the determination of the input assumptions after which the gas utilities can file their respective three-year DSM plans.

DECISION –PHASE 1

CHAPTER 1 - INTRODUCTION

The Ontario Energy Board (the “Board”) determined the original regulatory framework for gas utility sponsored Demand Side Management (“DSM”) programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, the gas utilities have filed DSM plans in response to the directives of the Board in the EBO 169-III Report.

The EBO 169-III Report provided guidelines to assist the utilities in the development and implementation of their respective DSM plans. Although the objectives and principles have evolved somewhat over the years to reflect changing market and industry conditions, they remain essentially unchanged. These DSM plans formed part of the gas utilities rate cases and were reviewed annually.

Over the past decade there have been occasions where rules for DSM programs have been challenged, requiring further interpretation and scrutiny by the Board. In addition, the Board has been required to frequently make decisions on similar DSM issues for the two large gas utilities, Union Gas Limited (“Union”) and Enbridge Gas Distribution (“EGD”), in separate proceedings. This has lead to increased regulatory burden for all parties and inconsistent practices by the two utilities. These concerns and the heightened focus on conservation and demand side management for the energy sector as a whole were the impetus for the Board to re-examine the DSM regime as it pertains to these two gas utilities through this generic proceeding.

In the Board's partial decision in EGD's 2006 rates application (EB-2005-0001 / EB-2005-0437), the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act, 1998 (the "Act"). The Board's findings in this decision, therefore, should be considered orders pursuant to section 36 of the Act.

The Notice further stated that the following would be among the topics the Board would evaluate in making orders relating to the operation, evaluation and auditing DSM plans starting January 1, 2007:

- timing of the schedule for submitting and reviewing DSM plans,
- determination and use of planning assumptions for generic energy efficiency measures and custom projects,
- DSM budget as a percentage of utility annual revenue,
- structure and screening of programs including differentiating between market transformation, lost opportunity and enabling activities,
- structure and use of LRAM, SSM and DSMVA,
- process and content of program evaluations including the requirement for a third party audit process,
- length of plan, as well as updating the plan and reporting requirements,
- rules respecting free riders and attribution of energy savings, and
- the appropriateness of directing specific DSM measures to low-income consumers.

Other areas of focus will include the requirement for and role of the Consultative committee, filing requirements for the DSM plans and reporting requirements.

As the content of the topic list indicates, the intent of the proceeding was to streamline processes, harmonize practices where appropriate and re-examine the rules of DSM that had developed to date.

It was not the intent to revisit the general principles adopted and conclusions reached in the Report of the Board E.B.O. 169 III regarding the appropriateness of Demand Side Management being utilized by the Utilities in Integrated Resource Planning (IRP).

In the course of the proceeding, the Board received three settlement agreements. The first was a complete settlement on some of the issues. The other two were partial settlements.

The first partial settlement contained issues that were settled as between EGD and Union on the one hand, and most of the intervenors on the other. Some of the issues in this package dealt with the financial issues and this “financial package” was considered by the parties to be un-severable. That is to say that the parties to this partial agreement regarded each of the elements of the package to be crucial to the package as a whole. Were the Board to disapprove of any discrete element of the package, the package as a whole would be withdrawn, and each of the elements would have to be litigated.

The second partial settlement contained proposals that were agreed to by all intervenors but not the utilities.

The Board held an oral hearing that commenced on July 10, 2006. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The non-utility parties to the hearing were Canadian Manufacturers & Exporters (“CME”), Consumers Council of Canada (“CCC”), Energy Probe, Green Energy Coalition (“GEC”), Industrial Gas Users Association (“IGUA”), London Property Management Association (“LPMA”), Low Income Energy Network (“LIEN”), Pollution Probe, School Energy Coalition ("SEC") and Vulnerable Energy Consumer's Coalition ("VECC").

The full record of the proceeding is available at the Board's offices. The Board has considered the full record but has summarized it in this decision to the extent necessary to provide context for its findings.

Chapter 2 deals with details of the completely settled issues. Chapter 3 addresses the issues contained in the "financial package". Chapter 4 deals with the remaining issues. Chapter 5 deals with the issues respecting a common set of input assumptions, a common guide and with next steps. In that regard, this decision document is referred to as Phase 1. Appendix 1 contains details regarding some of the procedural aspects of the proceeding, including a list of parties' representatives and witnesses.

CHAPTER 2 - THE SETTLEMENT PROPOSAL

A Settlement Proposal was filed with the Board on July 8, 2006 and was updated on July 11, 2006. The Board heard submissions from the parties and accepted the Settlement Proposal on July 11, 2006.

The Board acknowledges the effort of the participating parties to the Settlement Proposal and is pleased with the significant number of issues that were settled prior to the oral hearing.

Below are the completely settled issues which were accepted by the Board. To provide context to the balance of this decision, the Board sets out below the agreed upon phrasing of the settled issues. The numbering in brackets reflects the numbering that appeared on the Board's approved issues list for the proceeding.

Is a three year plan an appropriate term of a DSM plan? (Issue 1.2)

> "Parties agree that 3 years is an appropriate term for a multi-year DSM plan. Parties agree that the issue of whether and, if so, how a multi-year DSM plan should be aligned with a Utility's Incentive Regulation ("IR") period should be determined by the Board in the context of establishing the IR mechanism and rules, and cannot be determined in this proceeding in the absence of information on the structure and term of the IR regime adopted by the Board."

How are DSM parameters adjusted inside a multi-year rate making process? (Issue 1.6)

Parties referred this issue to completely settled Issue 1.2.

Should budgets, programs, targets, incentives and other plan components be established on an annual or multi-year basis? (Issue 1.8)

> "The approval of multi-year DSM plans will provide the utilities with the certainty of funding for programs which will have forecast life spans of more than one year. DSM plan components will be established at the outset of a multi-year DSM plan with the intention of applying throughout the currency of the multi-plan plan.
>
> As this settlement provides that the budget, SSM mechanism, LRAM, and DSMVA are all developed and measured on an annual basis within a multi-year plan, it is appropriate that amounts be recorded in all DSM variance or deferral accounts on an annual basis (market transformation amounts may be an exception)."

How should the budget be allocated between customer classes in rates? (Issue 1.9)

> "Cost allocation in rates shall be on the same basis as budgeted DSM spending by customer class. This allocation should apply to both direct and indirect DSM program costs."

Should the TRC [Total Resource Cost] test be the only test used to screen measures and/or programs for DSM plans? If no, what other tests should be used and how should these be applied? (Issue 2.1)

> "TRC shall be the only formal screen to determine whether a measure or program can be considered for inclusion in the portfolio. EBO 169-III identified numerous other considerations and tests that could be used to determine which measures and programs are actually selected for the portfolio in any given year, and those considerations and tests should continue to apply."

How should free rider and savings input assumptions be determined? (Issue 3.1)

> "Parties agree that input assumptions such as free rider rates, prescriptive measure savings assumptions, incremental equipment costs, measure lives and avoided costs (natural gas, electricity and water) shall be based on research utilizing the best available data at the time a multi-year plan or new program or significant new program design is developed. These assumptions shall be assessed for reasonableness prior to implementation of the plan or program and should be reviewed and updated on a regular basis during the plan period as part of each Utility's ongoing evaluation and audit processes."

What certainty is required that the assumptions are set for the duration of the DSM plan? (Issue 3.3)

> "The time at which changes in assumptions become effective shall differ depending on the use to which the assumption is being put:
>
> ***Program Design and Implementation.*** The Utilities agree to the principle that their DSM programs should be managed with regard to the best available information known to them from time to time. Normal commercial practice requires that a Company should react through changes to program design, implementation and/or mix, to material changes in base data as soon as is feasible given relevant operational considerations.
>
> ***LRAM.*** Assumptions used will be best available at the time of an audit. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for LRAM purposes from the beginning of 2007 onwards until changed again.

SSM. Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again."

What is the mechanism to determine if an input assumption needs to be reviewed or researched? (Issue 3.4)

"The Utility may of its own initiative or at the request of the Evaluation and Audit Committee ("EAC") commence a review of or research into assumptions."

How should the (LRAM) mechanism be structured? (Issue 4.2)

"The parties agree that the LRAM mechanism shall be calculated using the assumptions and savings estimates approved in the plan and adjusted for the audited Evaluation Report results.

For Union, the first year impact will be calculated as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

For EGD, the first year impact will be calculated on a monthly basis based on the volumetric impact of measures implemented in that month multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

Both of these processes for the Utilities reflect the status quo.

The LRAM account shall be cleared annually.

For purposes of clearing LRAM, input assumptions will be adjusted on an annual basis, as a result of the evaluation and audit work completed and shall apply from the beginning of the year being audited. See also Issue 3.3."

What evidence should be submitted to demonstrate that all conditions for clearance have been met? (Issue 4.3)

"Parties agree that the Utilities shall file an Audit report and any other backup needed to support the volumes used in the LRAM calculation. The Audit report will be prepared by an independent auditor to ensure accordance with Board approved rules. The auditor shall provide an opinion on the LRAM proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in Issue 9.3."

Is a third party audit required to verify LRAM calculation prior to clearance? (Issue 4.4)

"Yes, see issue 4.3 above."

How should LRAM costs be allocated between customer classes? (Issue 4.5)

"The LRAM shall be recovered in rates on the same basis as the lost revenues were experienced so that the LRAM ends up being a full true-up by rate class."

Should an incentive mechanism be in place? If yes, (Issue 5.1)

"Yes."

Is a third party audit required to verify year-end SSM calculation? And if required, what should be the audit principles, scope and timeline? (Issue 5.3)

"Parties agree that an independent auditor shall complete an evaluation audit with the purpose of verifying the claimed financial results and that the DSM shareholder incentive amounts (being the SSM and the incentive available in respect of market transformation programs) are calculated in accordance with the Board approved methodology. The audit shall provide an opinion on the DSM shareholder incentive amounts proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in issue 9.3."

How should SSM costs be allocated between customer classes? (Issue 5.4)

"Parties agree that DSM shareholder incentive amounts shall be allocated to the rate classes in proportion to the net TRC benefits attributable to the respective rate classes."

What evidence is required to clear the DSMVA? (Issue 6.4)

"The utility shall clear DSMVA amounts, subject to review as a component of the DSM audit, to ensure compliance with the Board approved rules. The utility shall include the DSMVA as part of the audit described in issue 9.3. The utility may recover the amounts in the DSMVA from ratepayers provided it has achieved its annual TRC savings target on a pre-audited basis and the DSMVA funds were used to produce TRC savings in excess of that target on a pre-audited basis."

How should DSMVA balances be allocated between customer classes? (Issue 6.5)

"The Utilities shall allocate the DSMVA amounts in rates based on the Utility's DSM spending variance for that year versus budget, by customer class. The actual amount of the variance versus budget targeted to each customer class shall be allocated to that customer class for rate recovery purposes."

Should the DSM consultative be continued? If yes, (Issue 7.1)

> "When required or useful, the utility will engage and seek advice from a variety of stakeholders and experts in the development and operation of its DSM program. As the utility is ultimately responsible and accountable for its actions, consultative activities shall be undertaken at its discretion. However, at a minimum, each utility will hold two consultative meetings annually. The purpose of the meetings will be to:
>
> - Review annual results (the Evaluation Report will be sent to the Consultative annually for review) and select the Evaluation and Audit Committee ("EAC"). Three members will be selected using the current process used to select the Audit Sub-Committee; the fourth member will be the utility. In the current process, the members of the Consultative nominate individuals to stand on the committee. Then each member of the Consultative votes for the three members they would like on the committee. The three with the highest number of votes form the committee.
>
> - Review the completed evaluation results.
>
> The Utilities each acknowledge the principle that stakeholder consultation has proved valuable. They each intend to continue to take advantage of the input of the consultative as long as the consultative is adding value and the overall cost of the process is reasonable."

What role should the Consultative have in the DSM planning, design, approval and audit process? (Issue 7.2)

Settlement on this issue was referred to completely settled Issue 7.1.

How often should the Consultative and LDCs meet? (Issue 7.3)

> "A utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement, subject to the requirement to meet twice annually set out under Issue 7.1 above. See Issue 7.5."

What is the appropriate amount that should be budgeted for Consultative and Sub-committee expenses? (Issue 7.4)

> "The utility shall determine as part of the planning process, the appropriate amount to include in its overall DSM budget for stakeholder engagement, based on anticipated needs."

How should participation in the Consultative committee be determined? (Issue 7.5)

> "The utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement. All intervenors in the Utility's most recent rate case shall be entitled to participate in the consultative meetings described in issue 7.1 above."

Should a percentage of the DSM budget be allocated to research? If yes, (Issue 8.1)

> "Parties agree that the Utilities should conduct forward-looking DSM research. The appropriate level of budgets for research shall be determined by each Utility from time to time (depending upon need, market conditions, etc.) and each Utility should include a summary of its forecasted research in its multi-year DSM plan filed with the Board."

How should it be determined that research is required and when? (Issue 8.2)

> "The utility shall determine the research needed to inform program assessment as part of its ongoing operational responsibilities and to ensure the long term viability of its DSM program. In making this

determination, the Utility shall give due consideration to any recommendations of the EAC, the Auditor, and the consultative."

To reduce duplication, should certain research commitments be combined for both LDCs? (Issue 8.3)

"Each Utility shall be responsible and accountable for its research activities and expenses. The utility is expected to seek and leverage efforts with third parties where appropriate but it is recognized that unique circumstances and objectives may exist that preclude partnering in some instances."

How often should a DSM market potential study be conducted by the LDCs? (Issue 8.4)

"Market potential studies, or updates to an existing study, must be filed by each Utility together with its multi-year plan. The Utility may, in its discretion, do additional studies of market potential or updates during its plan."

What is the purpose of evaluation reports and what should they contain? (Issue 9.1)

"EGD and Union are accountable to the Board to develop and implement cost effective DSM programs including the monitoring and evaluation of results. In order to inform stakeholders on the activities and results of the DSM programs undertaken, the utility shall file annually, a clear and concise Evaluation Report that summarizes the savings achieved, budget spent and the evaluations conducted in support of those numbers.

It is the purpose of the evaluation and audit process to review all input assumptions related to the delivery of DSM over the period of the multi-year plan. To assist with that purpose, the parties propose the establishment of an EAC to engage stakeholders in the development of an evaluation plan and budget and to engage stakeholders in a review of the evaluation results as they become available over the term of the plan."

Is a third party audit of the evaluation report required? And if required, what should be the audit principles, scope and timeline? (Issue 9.3)

"The parties agree that a third party audit of the Evaluation Report is required. The auditor will be retained by the utility who determines the scope of the audit. It will be the role of the auditor to:

- Provide an opinion on the DSMVA, SSM and LRAM amounts proposed and any amendment thereto
- Verify the financial results in the Evaluation Report to the extent necessary to give that opinion
- Review the reasonableness of any input assumptions material to the provision of that opinion
- Recommend any forward looking evaluation work to be considered

The auditor shall be expected to take such actions by way of investigation, verification or otherwise as are necessary for the auditor to form their opinion. The auditor, although hired by the utility, must be independent and must ultimately serve to protect the interests of stakeholders."

Should there be an Audit Sub-committee with intervenor participation? And if yes, what role should the Audit Sub-committee have? (Issue 9.4)

"As described in Issue 9.3 above, parties agree that there should be an audit subcommittee entitled EAC. Participation in the EAC will be determined as set out in Issue 7.1.

The EAC will provide formal input into the evaluation plan. In regards to evaluation activities the EAC will continue to have an advisory role in the following:

- Consultation prior to the filing of the DSM plan on evaluation priorities for the next three years (or the duration of the multi-year plan). The utilities will, as part of their implementation plan, review all of the input assumptions over the course of each multi-year plan.
- Review and comment on evaluation study designs. Input on the research methodology used to determine the input assumptions.
- Reviewing the scope and results of evaluation work completed on new programs introduced over the course of the multi-year plan.
- Selection of the independent auditor to audit the Evaluation Report and determine the scope of the audit. The EAC will ensure that all comments on the Evaluation Report from the Consultative are reviewed by the auditor.
- Following the audit, review of the Evaluation Plan annually to confirm scope and priority of identified evaluation projects.
- The EAC will be responsible for meeting the reporting guidelines of the Board (found at Section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities). The EAC will provide a final report within 10 weeks from the later of, the receipt of the Evaluation Report and supporting evaluation studies from the Utility, or the hiring of the auditor. Recommendations of the EAC with respect to DSMVA, LRAM and SSM clearances shall be included in the EAC's final report. The EAC shall not consider any further information subsequent to the Board's filing deadline each year."

What characteristics are required to determine that a program is either a market transformation or lost opportunity program? (Issue 10.1)

"Market Transformation programs are those that (a) seek to make a permanent change in the market for a particular measure, (b) are not

> necessarily measured by number of participants and (c) have a long term horizon.
>
> Lost Opportunity programs are those that focus on DSM opportunities that will not be available, or will be substantially more expensive to implement, in a subsequent planning period."

How should it be determined that utility has achieved any prescribed target? (Issue 10.3)

and

What should be the length of a market transformation and lost opportunity program? (Issue 10.5)

and

What is the appropriate level of funding for a market transformation or lost opportunity program? (Issue 10.6)

Settlement on these issues was referred to completely settled Issue 10.7.

How should a program incorporate the following elements; information and education activities; incentives; research; activities to reduce market barriers such as building codes and energy efficiency appliance standards; and coordination with other entities (e.g. OPA)? (Issue 10.7)

> "For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals."

Is it appropriate to use DSM funds for fuel switching to natural gas? (Issue 14.1)

> "Fuel switching is an important activity that can help alleviate some of the electricity supply programs faced by the province; however, the utility shall not use DSM funding to promote fuel switching to natural gas. The utility will pursue fuel switching activities as part of its marketing efforts that will be included in its rate case or other suitable application."

Is it appropriate to use DSM funds for fuel switching away from natural gas? (Issue 14.2)

> "Where fuel switching away from natural gas aligns with the Utility's DSM objectives the Utility may pursue these activities."

CHAPTER 3- PARTIAL SETTLEMENT (FINANCIAL PACKAGE)

In addition to the completely settled issues, the Board was presented with a list of partially settled issues. Union, EGD, CCC, SEC, Energy Probe, IGUA, LPMA, and VECC (the "Partial Settlement Proponents") were parties to a complete agreement on a number of issues. Certain of these issues were presented as a package (the "Financial Package") which the parties presented as being un-severable; i.e. if the Board did not accept the entire package, the Financial Package agreement would be withdrawn. The Financial Package dealt with:

- DSM budgets (Issue 1.3),
- DSM plan targets (Issue 1.4),
- allocation of DSM budgets amongst customer classes (Issue 1.7),
- the DSM incentive mechanism (Issue 5.2),
- the DSM variance account (Issues 6.1, 6.2, 6.3),
- market transformation and lost opportunity program budgets and utility incentives related to them (Issues 10.2, 10.4, 10.8), and
- targeted programs for low income customers (Issues 13.1, 13.2, 13.3).

The Partial Settlement Proponents explained that the individual elements of the Financial Package were tied together, and that to change one element would have repercussions on other elements. On the opening day of the hearing, the Board explained to the parties that it would hear whatever evidence the parties chose to lead; however, if at the conclusion of the hearing the Board determined that it did not wish to accept the Financial Package in its entirety, it would not re-open the hearing to hear fresh evidence on any of the issues. The Partial Settlement Proponents subsequently informed the Board that they would continue to exclusively support the Financial Package, and would not present any evidence to be considered in the event that the Board did not accept the entire Financial Package.

In addition to the Financial Package, the Partial Settlement Proponents reached a partial settlement on a number of other issues that could be considered individually. This chapter deals only with the Financial Package; the remaining partially settled issues will be addressed in Chapter 4.

The chief proponents of the Financial Package in the hearing were the utilities through their witness panels. The other Partial Settlement Proponents did not present witnesses in support of the Financial Package, but did conduct what was described as “friendly” examinations of the utility witnesses on these issues. The parties opposed to the Financial Package cross-examined the utility witnesses and, in some cases, filed their own proposals.

The Board will accept the Financial Package as presented by the Partial Settlement Proponents. As the Board explained when considering the meaning of a partial settlement on July 10, the Board has considered all of the issues in the Financial Package on an issue by issue basis. Taken individually and as a whole, the Board finds all of the proposals contained in the Financial Package to be reasonable.

The Board is pleased that the Financial Package amounts to what is largely a “rules-based” approach. Many of the major elements of the three year DSM plans will essentially be locked in for the term of the plan, and will not require further review by the Board during this period. This should result in significant regulatory savings for the parties, the Board, and, ultimately, for ratepayers.

The Board finds that the Financial Package strikes an appropriate balance between advancing DSM forward through higher budgets and ultimately higher TRC savings targets, while not forcing the utilities to try to spend money that they indicated they would have trouble spending in a cost effective manner. The Board is also satisfied that the Financial Package will not cause undue rate impacts to ratepayers given the relatively modest nature of the proposals, in light of the overall revenue requirement of the respective utilities.

In addition to the overall comments above, the Board has the following remarks on the individual issues that comprise the Financial Package.

How should the financial budget be determined? (Issue 1.3)

The Partial Settlement makes the following proposal.

> "Parties in agreement with this partial settlement accept that a DSM budget cap should be developed using the following formulaic approach in each year of a multi-year DSM plan. For the first year, the budget for EGD will be $22.0 million, an increase of $3.1 million or approximately 16% from its 2006 budget. For Union, the 2007 budget will be $17.0 million an increase of $3.1 million or approximately 22% from its 2006 budget.
>
> In the second and subsequent years of a multi-year DSM plan, the DSM budget for each year of the plan will be determined by applying an escalation factor of 5.0% for EGD and 10% for Union to the budget developed for the immediately preceding year. The purpose of the application of different escalation factors for EGD and Union is to address the desire by some parties that the difference between the level of spending by EGD and Union be narrowed. The parties agree that this formula results in budgets of $23.1 million and $24.3 million for EGD in 2008 and 2009 respectively, and budgets of $18.7 million and $20.6 million for Union in 2008 and 2009 respectively.
>
> Parties to this partial settlement agree that the Utilities remain obligated to develop, and spend monies on, cost-effective DSM programs up to the budget amount developed by this methodology."

The Board is satisfied that the Financial Package proposal reaches an appropriate balance between increasing DSM budgets and approving budgets which can be spent in a cost effective manner. Both Pollution Probe and GEC argued in favour of much higher budgets; however, the Board is not convinced that the utilities could currently spend these amounts cost-effectively.

Should there be plan targets and if so, should they be volumetric or based on TRC values? (Issue 1.4)

The Financial Package agreement makes the following proposal:

> "Parties to this partial settlement further agree that there will be an annual TRC target. The parties agree to phase in a formula over the next three years which will set this target, as described below, by averaging the Utility's actual audited TRC results over the previous three years and applying to this figure an escalation factor equal to 1.5 times the amount by which the utility's budget is increased. The parties agree to phase in the aforementioned formula over the next three years beginning with an agreed upon target for each utility in 2007 which, for Union will be $188 million and for EGD $150 million.
>
> Furthermore, the parties agree that, in the event the avoided costs used by the utility are, at a later date, updated, the actual audited results from previous years used to calculate the target will be adjusted to reflect these updated avoided costs.
>
> Finally, and for greater certainty (and as an example), set out below is the formula by which the target will be set for Union, with 2010 provided for illustrative purposes only:
>
> • 2007 - $188 million.
>
> • 2008 - The simple average of $188 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

• 2009 - The simple average of $188 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

• 2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

For EGD, the formula by which the target will be set is as follows, with 2010 provided for illustrative purposes only:

• 2007 - $150 million

• 2008 - The simple average of $150 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

• 2009 - The simple average of $150 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

•2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie.7.5%).

The "actual audited TRC values" shall be the total TRC produced for the year in question as determined by the audit in the following year. In setting the target for 2009 and subsequent years, the actual audited TRC value for the immediately preceding year, but not for the prior two years used in the average, will be adjusted to reflect any changes in input assumptions determined in the audit to apply to that year for LRAM purposes. By way of example, if a free rider rate is increased in the 2009 audit carried out in the first half of 2010, under the partial settlement that change would normally apply to SSM for the years 2010 and thereafter, but to LRAM for 2009 as well. In calculating the target for 2010, the three year average will use the TRC values otherwise determined for 2007 and 2008, but for 2009 will use the audited TRC values, adjusted for that change in free rider rate identified in the audit."

The Board is satisfied that the Financial Package proposal sets reasonable TRC targets for the utilities. The Board notes that the formula used to derive the targets in years two and three of the plan is self adjusting to account for actual performance in the previous year. The Board finds this formula to be preferable to setting the targets for all three years in advance.

The Board notes that the target for Union in year one of the plan will actually be lower than its Board approved target for 2006. The Board heard evidence from Union that the TRC target for 2006 had been set at a level that it will not attain. Union indicated that according to its current projections for 2006, the company will likely achieve TRC savings in the range of $170 million (on a target of $216 million). The Board accepts Union's evidence in this regard, and finds that a target of $188 million in year one of the three-year plan is reasonable.

On what basis should the DSM program spending be targeted amongst customer classes? (Issue 1.7)

The Financial Package agreement makes the following proposal:

> "Parties acknowledge that EGD's and Union's rate classes and customer needs are not identical, and hence it is not appropriate to restrict spending based on a rigid formulaic approach by rate class. The Utilities acknowledge and accept the principle that their portfolio of DSM programs should provide customers in all rate classes and sectors with equitable access to DSM program(s) to the extent reasonable, and that this principle must be balanced and consistent with the principle of optimizing cost-effective DSM opportunities. To the extent that a proposed multi-year plan proposes DSM sector (ie. residential, commercial, or industrial) level spending that is significantly different than the historical percentage levels of spending in those sectors, the utility will provide its explanation for this in its proposed multi-year plan. Parties may challenge any such

explanation, or its impacts. The Board will then determine whether to approve the revised spending ratios, and if so, under what conditions.

To the extent that actual sector level spending then varies significantly from the ratios identified in the plan, parties may challenge the appropriateness of the deviation from the plan when the utility seeks approval for the clearance of relevant accounts and the Board can make such order as is appropriate. (Issue 1.7)"

The Board is cognisant of the tension between ensuring that each rate class is allocated an appropriate portion of DSM funds on the one hand, and the benefits of targeting spending to the most cost effective programs regardless of what rate class they fall in on the other. The Board is satisfied that the Financial Package proposal finds the appropriate balance.

What is an appropriate incentive mechanism and how should it be calculated? (Issue 5.2)

The Financial Package agreement makes the following proposal:

"The parties to this agreement agree that an SSM shall be established for the first year of the plan and shall be in effect for each year of each multi-year plan.

Parties agree that the amount of any SSM shall not be included in the Utility's return on equity ("ROE") for the purposes of setting rates or in the calculation of any earnings sharing amounts.

The parties agree that for the purposes of this settlement, the TRC indexing target for 2007 for EGD will be $150 million, and for Union, $188 million. Targets for subsequent years shall be set in accordance with the formula in Issue 1.4. The cumulative SSM incentive payment to each utility for achieving their respective TRC target will be set by a formula, and at 100% of TRC target will be $4.75 million. For the purposes of determining whether each utility has met its 100% TRC target, the input assumptions for the calculation of SSM will not be changed retroactively. For clarity, changes to input assumptions, which are confirmed through audit, apply in the year immediately following the year being audited. For example, input assumptions for purposes of the SSM remain fixed for 2007, and any changes to input assumptions which change as a result of the audit of the 2007 results which is undertaken in early/mid-2008 will apply from the beginning of the 2008 year forward. Also see Issue 3.3.

For both Utilities, the following formula applies for the determination of the SSM curve and resulting cumulative payout. The SSM payout will be calculated based on the results as they apply along the curve and each of the following percentage thresholds do not represent lump sum payments for reaching the threshold but simply serve to structure the SSM curve based on targets and SSM amounts as agreed to by the supporting parties:

Up to 25% of the annual target, a total payout of $225,000
Up to 50% of the annual target, a total payout of $675,000
Up to 75% of the annual target, a total payout of $2,250,000
Up to 100% of the annual target, a total payout of $4,750,000
Up to 125% of the annual target, a total payout of $7,250,000
In excess of 125% of the annual target, a total that is capped at no more than $8,500,000.

The parties agree that the annual ‘cap’ of $8.5 million will increase annually by the Ontario CPI as determined in October of the preceding year (i.e., the 2008 cap will increase based on CPI as determined at October of 2007).

See also issue 10.4 for the incentive available to the utilities in respect of market transformation programs”

During the hearing, the utilities provided the formula in calculating SSM, which is reproduced below:

> "For achievement of between 0 and up to 25.0% of the annual target, the SSM payout shall equal $900 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 25.0% up to 50% of the annual target, the SSM payout shall equal $225,000 plus $1,800 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 50.0% up to 75.0% of the annual target, the SSM payout shall equal $675,000 plus $6,300 for each 1/10 of 1% of target achieved above 50.0%, and
>
> For achievement of greater than 75.0% of the annual target, the SSM payout shall equal $2,250,000 plus $10,000 for each 1/10 of 1% of target achieved above 75.0% to a maximum of the SSM annual cap."

There was a complete settlement on issue 5.1, in which all parties agreed that there should be an incentive mechanism. The Financial Package proposal for issue 5.2 presents a formula for determining the exact amount of the SSM payout based on the level of success each utility has achieved in hitting its TRC targets. The Financial Package proposal calls for an escalating incentive scale which starts at the first dollar of TRC net benefits achieved. This proposal marks a change from the current Board approved practice where the utilities are required to reach a certain level of net TRC savings before any incentive is realized. The Board is satisfied that this change to the *status quo* is appropriate. The Board is persuaded by the utilities' evidence that the proposed structure is more likely to attract management attention to DSM programs. The Board is also comforted by the fact that the incentive payments for performance below 50% of the TRC target is very low. Further, the $8.5 million cap on incentive payments for any one year ensures that ratepayers will not have to pay an undue amount if a utility achieves extraordinary success.

Demand Side Management Variance Account (Issues 6.1, 6.2, 6.3)

The Financial Package agreement makes the following proposals:

> “Parties agree that the DSMVA shall be continued. The DSMVA shall be used to “true-up” the variance between the spending estimate built into rates for the year and the actual spending in that year. If spending is less than what was built into rates, ratepayers shall be reimbursed. If more is spent than was built into rates, the utility shall be reimbursed up to a maximum of 15% of its DSM budget for the year. All additional funding must be utilized on incremental program expenses only (i.e. cannot be used for additional utility overheads). For greater certainty, program expenses include market transformation programs. ”
>
> “There should be no limit on the amount of under spending from budget that should be returned to ratepayers. Parties agree that a Utility may spend and record in the DSMVA for reimbursement to the utility, in any one year, no more than 15% (fifteen per cent) of that Utility’s DSM budget for that year. ”

The Board finds the Financial Package proposal to be reasonable. The DSMVA will allow utilities to aggressively pursue programs which prove to be very successful, even where this causes them to exceed the Board approved budget (by up to 15%). It will also ensure that unspent DSM funds are returned to ratepayers.

Market Transformation (Issues 10.2, 10.4, 10.8)

The Financial Package agreement makes the following proposals:

> “Every utility DSM plan should include an emphasis on lost opportunity and market transformation programs and activities. For purposes of this agreement, parties agree that this emphasis will consist of a market transformation budget of $1.0 million per utility per year and is included in the total budget amounts referenced in issue 1.3.”
>
> “Parties agree that each utility is entitled to an incentive payment of up to $0.5 million in each year of the multi-year plan based on the measured success of market transformation programs. The measurement and calculation methodologies to determine whether this amount has been earned in the year shall be detailed by each utility in its multi-year DSM plan. For clarity, this amount is in addition to any amount earned at issue 5.2. By way of example, a Utility may propose in its DSM plan a program to increase the market share of a particular high efficiency product, and a $250,000 annual incentive based on the market share of that product at the end of each year, measured by a specific third party market index, being 10% higher than the previous year. If the DSM plan is approved by the Board including that program, the Utility will be entitled to a $250,000 incentive in each year that it meets the stated market share goal.”
>
> “For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals.”

The Board is satisfied with the Financial Package proposal for market transformation. GEC argued for a much larger budget for market transformation and lost opportunity projects. Utility witnesses stated that the utilities could not effectively spend these budgets. The Board notes that the proposal regarding utility incentives for these programs does not achieve the level of certainty that exists for other elements of the Financial Package. While GEC argued for a more concrete incentive mechanism, the witnesses at the hearing were largely in agreement that market transformation programs are not necessarily amenable to fixed and inflexible rules. The Board agrees. The Board therefore accepts the proposal as filed.

Targeted Programs (Issues 13.1, 13.2, 13.3)

The Financial Package agreement makes the following proposals:

> "Parties to this settlement accept that low-income customers face barriers to access DSM programs which are unique to this group of customers. Accordingly, parties to this settlement agree that it is appropriate to establish a minimum amount of spending on targeted low-income customer programs in the residential rate classes of both Utilities. It is agreed that each utility will spend out of its DSM budget a minimum of $1.3 million, or 14% of each respective utility's residential DSM program budget, whichever is greater. For clarity, a utility may expend more than $1.3 million or 14% of its residential DSM program budget if the utility considers it appropriate. The Utilities each agree to increase the $1.3 million spending floor by the budget escalation factor appropriate for the utility (i.e. EGD 5%; Union 10%) in each of the second and third years of a three year plan.
>
> The parties to this settlement further agree that of the $1.0 million budget for market transformation programs, each utility will expend no less than 14% on targeted low-income market transformation programs.

> The Utilities agree that by the establishment of this spending level floor, they will not, as a result, reduce planned DSM spending in other rate classes or sectors which are directed at low-income residents (e.g. social housing multi-unit residential spending) or their spending on fuel switching targeted to low-income customers."
>
> "Each of the utilities is at liberty to develop appropriate eligibility criteria for low income residential programs, and each utility agrees to consult with VECC in respect of the development of eligibility criteria and low-income program parameters. Parties to this settlement generally accept that criteria presently used by various levels of government for the purposes of determining low income eligibility may be appropriate for use by the utilities."

The only customer segment proposed to the Board for targeted programs were those for low-income customers. The Board finds the Financial Package proposal to be reasonable. The proposed spending floor should ensure that low-income consumers have access to DSM programs at least in approximate proportion to their percentage of residential revenue. LIEN argued that spending on low-income DSM programs should be equal to 18% of the total residential class DSM budget, assuming the total DSM budget is split proportionately amongst all rate classes. Under Issue 1.7, the Board has already stated its acceptance of budget allocations that are not strictly proportional to customer class revenue. There was conflicting evidence in the hearing as to the estimated proportion of low-income households within the residential sector. LIEN argued that the proportion was 18% while the Partial Settlement proponents argued that 14% was closer to the actual proportion. The Board finds LIEN's evidence on this matter unconvincing and finds that 14% is supported by the evidence. The Board, therefore, accepts the proposal that each utility will annually spend 14% of the residential DSM budget or $1.3 million on low-income programs, whichever amount is greater.

CHAPTER 4 - REMAINING NON-SETTLED ISSUES

The previous chapter, Chapter 3, dealt with the settled issues and the partially settled issues that were presented to the Board as a “financial package”. The following chapter, Chapter 5, includes discussion of Issue 3.2 relating to the question of whether there should be a common guide. This chapter, Chapter 4, deals with the remaining non-settled issues that were addressed during the oral hearing.

What should be the timing of the schedule for submitting and reviewing Demand Side Management (“DSM”) plans? (Issue 1.1)

The Board was presented with a partial settlement. All intervenors agreed as follows:

> “…DSM plans should be filed at least nine months prior to the plan period to which they relate, to give sufficient time for stakeholders and the Board to consider them, and for Board approval prior to the plan period commencing.”

The utilities believe that filing the DSM plans four months in advance of the initial plan year will allow sufficient time to have the plan in place by the beginning of the following year. The utilities indicated that this would allow them to file final results from the previous year’s audit, rather than interim un-audited results.

For clarity, the timing issue here relates to future DSM plans. The timing of filing for the inaugural three-year plan is dealt with elsewhere in this decision.

The Board notes that a filing date at least nine months in advance would entail the presentation of un-audited performance of the plan’s second year. This may likely involve updates once the results are audited. The Board is of the view that updates should be avoided where possible, as they are generally not conducive to an efficient review. While the Board anticipates that a four month time frame will likely be adequate to accomplish the review given the rules approach adopted by the Board, there is the possibility that it will not. In that case, the consequence is a start date that may not immediately follow the last day of the previous term of the plan. While this may not be desirable, it would be of little adverse consequence as the previous plan would continue. It is in the Board's view a reasonable risk to take in order to obtain the benefits of an efficient review. The Board therefore accepts the utilities' proposals that subsequent plans be filed four months in advance of their commencement.

What process and rules should be available to amend the DSM plan? (Issue 1.5)

There was no settlement (complete or partial) on this issue.

In a response to an undertaking (J2.2), the utilities referenced the preamble of the Partial Settlement which reads

> "For greater clarity, where any settled issue is expressed to continue throughout a multi-year plan, no party to that settlement may seek to re-open that issue with respect to either Utility in any other proceeding prior to the earlier of a) the Board's consideration of the multi-year plan of that Utility, or b) a further hearing on DSM in which the Board has determined that such issue is to be considered "

and stated that

> "… it is the position of the utilities that the Board should amend a multi-year plan during the currency of that plan only in exceptional circumstances. It is expected that with the proposed language, all stakeholders will recognize that any application for an amendment must meet a very high onus to demonstrate undue harm. The intent of the above section is not to provide parties with an opportunity to reopen the framework rules established in this proceeding."

As noted at the oral hearing, no rule can prevent requests for review, or should for that matter. It would not be in the public interest to disallow re-opening of the plan in midstream under any circumstances. At the same time, the purpose of this generic initiative is to avoid unnecessary re-visitation of DSM issues.

Demonstration of “undue harm” was accepted as a reasonable principle by intervenors. The Board concurs that it is a workable principle and useful in the circumstances. There was also support for the proposal by SEC that any party claiming undue harm must first seek leave of the Board before the matter is thoroughly reviewed, and leave should be given only in exceptional circumstances. The Board notes that if a proposed amendment came forward either by way of a motion or by way of application, the Board has the authority and tools to subject the request to the appropriate scrutiny, and to ensure that the intentions of the parties and the Board are respected.

As for the proposal by the utilities that the Board use its cost assessment powers as a further measure to dissuade frivolous requests, this option is always available to the Board and can be used when warranted. This applies equally to intervenors and the utilities.

Should a TRC threshold be established to determine if a measure and/or program is cost effective or should it be based on the cost effectiveness of the portfolio? If so, what should the value be? (Issue 2.2)

The Board was presented with a partial settlement. All parties except SEC agreed as follows:

“The general principle is that all measures and programs should exceed a benefit to cost ratio of 1.0 to be included in the portfolio, but exceptions are reasonable where other benefits are apparent (e.g., pilot programs).”

SEC argued for a screen value of 1.2 rather than 1.0 on the basis that TRC is based on assumptions that change, so it would be appropriate to build in a margin to ensure feasibility. SEC noted that nothing is lost since it appears that there is much more DSM available than the utilities can handle and thus, instituting a higher threshold programs would be better. SEC noted that the exception related to the screen value for pilot programs would still exist.

In the Board's view, the availability of DSM initiatives that exceed the 1.0 cost-benefit ratio is not a compelling argument for deviating from a widely-practiced threshold of 1.0. A program that yields a benefit cost ratio over 1.0 does provide positive net benefits and it would not be appropriate to knowingly forego such benefits. As for SEC's argument that a higher threshold would avoid the risk of uneconomic programs, this can be addressed by instituting more robust input assumptions. Moreover, the risk of uneconomic programs is offset by the fact that, from a societal perspective, the TRC test does not reflect the positive aspects of mitigating negative externalities that are inherent in gas consuming activities. In fact the risk of undertaking uneconomic programs is self-correcting by the incentive by the utilities to maximize rewards by maximizing TRC benefits. For the above reasons, the Board does not accept SEC's suggestion.

However, the Board notes that the partial settlement refers to pilot programs as an example of programs where an exception to the threshold of 1.0 may be permitted. The implication is that there may be other types of programs. No other examples were provided. The Board prefers more certainty as to the exceptions in these circumstances. The Board therefore finds that the exception to the TRC threshold should be restricted to pilot programs at this time.

How often should avoided gas costs be calculated and should the Local Distribution Companies ("LDCs") use identical avoided costs? (Issue 3.5)

There was no settlement (complete or partial) on this issue.

EGD undertook to explore if the utilities could produce a common set of avoided costs and responded (J2.4) as follows:

> "Each Utility will calculate avoided costs for natural gas, electricity and water that reflect the cost structure and service territory of the Utility. In order to ensure consistency, a common methodology will be used to determine the costs. The Utilities will coordinate the timing for selecting commodity costs so that they are comparable.
>
> The avoided costs will be submitted for review as part of the multi-year plan filing and should be in place for the duration of the plan. The commodity portion of the avoided costs will be updated annually.
>
> As avoided costs are long term projections, updating the costs, other than the commodity costs, on a three year cycle should not cause benefits to be significantly under or overstated. Regardless of how often the avoided costs are updated, the same avoided costs will be used to calculate both the target (relative to 2007) and incentive amount, therefore it is anticipated that the relative impact would be minimal."

Only GEC argued against the utilities' proposal. It argued that the utilities should use common values for gas commodity, electricity and water. With respect to the avoided distribution system costs (e.g. pipes and storage etc.) which may vary by utility, GEC submitted that the utilities should be required to demonstrate how different these values are so that the Board can determine whether or not the difference is material.

The Board does not accept GEC's proposals. Avoided gas costs are a significant component of calculating TRC benefits. Gas costs can be different for each utility depending on, among other things, its gas supply management policies and practices.

With respect to system costs, these are certainly unique to each utility and they too are an important part of the TRC benefit calculation. The benefits of estimating and measuring with more precision the TRC values for DSM programs outweigh, in the Board's view, the costs of the incremental effort to determine and review the different values for gas commodity and system costs.

The Board also notes that the methodology for estimating the values for natural gas commodity, system costs, electricity and water will be common for the two utilities, which will ensure some measure of consistency and efficiency.

The Board accepts the utilities' proposals.

Should the LDCs be entitled to revenue protection? (Issue 4.1)

The Board was presented with a partial settlement on this issue. All parties except CME agreed that the utilities should be entitled to revenue protection.

By accepting the "financial package" settled issues earlier in this decision, the Board has not found merit in CME's argument that the utilities should not be entitled to revenue protection. As long as a utility's fixed costs are not fully recovered through fixed charges (and part of the fixed costs are therefore being recovered through the variable charges), there is an inherent conflict for the utility between sales growth and conservation. The existence of a mechanism to neutralize this conflict through an LRAM mechanism is therefore essential to the success of DSM.

What is the appropriate level of funds that should be budgeted for an evaluation report and audit? (Issue 9.2)

The Board was presented with a partial settlement on this issue. All parties except GEC agreed as follows:

"The Utilities shall ensure that DSM budgets and spending include adequate funding to complete the required annual evaluation and audit activities. The utility is responsible and accountable to ensure that evaluation and auditing activities are concluded in a timely fashion and that the associated costs are reasonable."

GEC argued that 3% of the DSM budget should be allocated to evaluation and audit over the three year period. GEC noted that the utility should have the flexibility to move spending between years to balance the lumpiness of spending. GEC noted that this budget should only be spent if required.

The Board fails to see the rationale or benefit of GEC's suggestion. In fact the Board only sees lost DSM program opportunities as the utilities will not be able to access any unspent portion of a fixed budget reserved for evaluation and audit. The Board does not accept GEC's proposal. The utilities should be spending in evaluation and audit as required and as prudent.

What attribution rules or principles should be applied to jointly delivered DSM programs? (Issue 11.1)

There was no settlement (complete or partial) on this issue.

The issue for the parties was how the framework rules will deal with situations where a utility operates or participates in a program with a non-rate-regulated third party and, where this occurs, how should the determination of the TRC benefits be made. For completeness, the Board also makes a finding on attribution between Board rate-regulated parties.

The utilities advocated the centrality principle, as decided by the Board in EGD's EB-2005-0001 rate case. Under the centrality principle, it would be considered that the utility played a central role if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. In such circumstances the utility would be entitled to 100% of the TRC benefits.

Where the utility's role is not considered central, the utilities differed. EGD advocated a scaled role approach, whereas Union proposed that the attribution of TRC benefits would be measured by free ridership. In Union's view, there is no material distinction in the two approaches as both would likely produce the same result. The utilities agreed that it should be the same arrangement for both as determined by the Board.

In the view of CCC and GEC, the rule of centrality is not particularly helpful at avoiding the need to analyze each project or proposal.

The Board notes that the utilities did not dispute the suggestion that attribution of benefits for jointly delivered DSM programs must be done on a case-by-case basis. The Board agrees that this is a reasonable approach. The issue is whether the centrality principle should be maintained.

The Board recognizes that it accepted the centrality principle in the EB-2005-0001 rate case when it dealt with EGD's EnerGuide for Houses program. What makes the re-assessment necessary is the fact that this is a generic hearing for the gas distributors and it is appropriate to review the rules *de novo*. In that regard, the Board notes that, pursuant to the settled and approved issues, there is now a delineated role for the evaluation and audit committee in respect of programs pursuant to the settlement agreement and the Board's acceptance of the agreement. Specifically, the attribution rules set by the Board will be used by the evaluation and audit committee to assess and settle the TRC savings attributable to the utility's role, which will ultimately be reviewed by the Board.

As the utilities concede, the centrality rule is not absolute. There can be considerable judgment in determining whether or not the role of the utility is central in a particular program. Attribution on the basis of the utility's participation that is considered incremental to the program on the other hand appears to remove some of the controversy, and it does not preclude full 100% attribution to the utility. However, a drawback is that the incrementality approach may not adequately and fairly capture situations where a program would not have existed at all if it were not for the utilities.

On balance, the Board accepts the centrality principle for purposes of the first multi-year DSM plans, under which the utility would be entitled to 100% of the TRC benefits if it can be demonstrated that it has a central role in a program. That is, as the utilities proposed, if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. The experience to be gained over the next three years will inform as to the suitability of continuing with this approach after that point.

This leaves the difference in approach by the two utilities where centrality is not claimed or demonstrated.

The Board accepts the utilities' position that the distinction between their approaches is without a difference. The utilities' differences reflect different internal practices, as noted by the utilities. The utilities acknowledge that either approach would involve the evaluation of attribution of each program by the evaluation and audit committee, and ultimately by the Board. However the utilities accept that there should only be one common approach, to be determined by the Board.

The Board prefers the free ridership approach advocated by Union as this would be more consistent with the general approach for measuring TRC benefits in other DSM activities implemented by the utilities.

The TRC benefits for program partnerships with Board rate-regulated entities (e.g. electricity distributors) shall be allocated in the manner indicated in the electric TRC Guide, as was canvassed at the oral hearing. That is, a gas distributor partnering with an electricity distributor shall claim all of the benefits associated with the gas savings.

How should existing or future carbon dioxide offset credits be dealt with in DSM plans and programs, if at all? (Issue 11.2)

The Board was presented with a partial agreement on this issue. All intervenors agreed as follows:

> "Until the rules are known, a deferral account should be established for each Utility and any dollar amounts representing proceeds from the sale or other dealings in credits should be credited to that account".

The utilities submitted that until the rules of carbon dioxide offset credits are known, the Board should not make any determination on this issue.

The Board accepts the argument by certain intervenors that there is no harm in ordering a deferral account to capture any future carbon dioxide offset credits. While the matter could wait until the resolution, if any, of the carbon dioxide offset credits matter, the utilities did not present convincing arguments to counter the no harm proposition advanced by many intervenors. The Board is generally reluctant to authorize the establishment of deferral accounts without a more concrete and immediate need. However since this matter is within the scope of DSM, there is an opportunity to deal with it now without the need for further processes. Therefore the Board concludes that the establishment of a deferral account would be a reasonable approach in the circumstances, and so orders.

Should free riders for custom projects be determined on a portfolio average or on a project basis? (Issue 12.1)

There was no settlement (complete or partial) on this issue.

The utilities proposed that the free ridership rate should be determined on a portfolio average basis. The single free ridership rate would apply across a number of technologies and a number of sectors. The utilities proposed a free ridership rate of 30%.

VECC submitted that although the fairest way to address attribution for custom projects would be on a project-by-project basis, a portfolio average approach can be acceptable for administrative efficiency, but with the conditions that there should be emphasis on sector-by-sector as suggested by LPMA.

The Board sees merit in the notion of differentiated free ridership rates by market segment, at least for large and small enterprises. However, this is a significant undertaking. The utilities revealed that at present there are over one thousand custom projects within EGD and a fifth of that within Union. A segmentation analysis would need to be done on a sample basis, statistically justified, and reviewed by the parties and the Board. Ordering such studies for the two utilities for this plan may jeopardize the timetable of filing and implementing the respective DSM plans. The Board also notes the testimony by Union's witness that any differences in free ridership rates through market segmentation may at the end balance out and in fact support a single rate.

For these reasons the Board accepts a portfolio average approach for custom projects. The free ridership rate for custom projects will be determined as part of the process that will determine the input assumptions.

For the next generation multi-year plans, the Board expects the utilities to propose common free ridership rates for custom projects that are differentiated appropriately by market segment and technologies.

Should custom projects have a third party or an internal audit and if so, what would be the audit scope and process of the audit? (Issue 12.2)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Custom projects should be audited using the same principles as any other programs. Audit activities should be sufficient for the auditor to form

> an opinion on the overall SSM, LRAM and DSMVA amounts proposed in the Evaluation Report."

EGD proposed that the custom projects be audited as part of its portfolio results based on a significantly appropriate representative sample. The auditor would then confirm the results and these would be included for the purposes of calculating SSM and LRAM, consistent with the completely settled Issue 3.3.

Union proposed that, as custom projects form a large part of Union's DSM portfolio, they should be assessed by a third party, and noted that this is in fact Union's current practice. Union explained that a statistically significant sample of both the largest and smallest subset of projects should be evaluated by a third party evaluator, hired by the utility. The evaluator would not be the auditor because of the particular technical expertise required to review custom projects. The report of the technical expert would form part of the evaluation report, which would be forwarded to the auditor.

The Board notes that the distinction between the Union and EGD proposals is that, in Union's case, the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor. In EGD's case, that first cut is done in-house but EGD still engages a third party to do an evaluation of the sampling of its custom projects. Although in both cases the results would be forwarded to the auditor for review, the Board is of the view that a common approach should be adopted for the two utilities. The Board prefers Union's current practice where the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor.

Union proposed the adoption of the rule in the TRC handbook for electric CDM, where the projects selected for assessment should consist of a random selection of 10% of the large custom projects representing at least 10% of the total volume savings for all custom projects and consist of a minimum number of five projects. The Board adopts this proposal, which shall apply to both utilities.

[With respect to custom projects], how should savings be determined and what documentation is required? (Issue 12.3)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life, so for example should include a factor for the possibility that a measure will not be used for its entire engineering life (due to bankruptcy, change in operations, etc.)."

During the hearing, a complete settlement was considered to have been reached by all parties by truncating the text as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life."

The Board concurs with the settlement.

[With respect to custom projects], should the volumetric savings recorded be actual or forecasted volumes and what documentation is required to verify this result? (Issue 12.4)

In the Partial Settlement, parties referred this issue to Issue 12.3, which in turn was considered to have settled by the parties during the hearing.

The Board approves this settlement.

[With respect to custom projects], how will an appropriate base case be determined? (Issue 12.5)

The Board was presented with a partial settlement on this issue. All intervenors and Union agreed as follows:

> "Only the part of the project that the Utility influenced is to be counted for SSM or LRAM purposes."

The Board notes that only EGD opted out on the basis that it does not know the implications of the word "influence". The Board is not in a position to provide assistance to EGD in this regard as EGD itself was not clear as to the relief that it is seeking. However, the Board's findings in this decision taken in their entirety should help alleviate EGD's concerns. In particular, the Board does not see how the proposed wording would invalidate settled Issue 3.3, which is EGD's stated concern.

The Board accepts the partial settlement on this issue.

How should the funding levels and targets, if any, for the gas utilities' electricity to natural gas fuel switching programs be determined? (Issue 14.3)

The Board was presented with a partial settlement on this issue. All intervenors agreed as follows:

> "Programs promoting fuel switching to natural gas, which should be funded from the marketing budget of the Utility, should, just as with DSM programs, seek to balance maximization of TRC benefits with minimization of rate impacts."

Union noted that that all parties agreed that fuel-switching to natural gas is not a DSM activity (and DSM funds should not be used for this purpose) and fuel-switching away from natural gas may be appropriate in certain circumstances and may therefore constitute DSM. Union stated that it is simply seeking guidance from the Board or approval to bring an application in the future which will address the issue of the appropriate level of funding, as well as the target, if any, associated with fuel-switching, and thus how success ought to be measured.

EGD submitted that in accepting the completely settled issues in this matter, the Board has effectively deferred the issue to a future panel of the Board that will consider it in the context of whatever proceeding any fuel-switching budget is brought forward.

In this Board Panel’s view, making findings, providing guidance or even commenting on the substantive matters of fuel switching would not be appropriate. In making this finding, the Panel was mindful of the impact any conclusions may have on a future panel of the Board. Equally important, there was an insufficient evidentiary basis in this proceeding for the consideration of limiting fuel-switching to a TRC test only. Parties that believe that a TRC test should be used for a fuel-switching budget will have the opportunity to raise this issue in future rate proceedings.

What is the appropriate role of gas utilities in electric CDM? (Issue 15.1)

There was no settlement (complete or partial) on this issue.

EGD submitted that it would like to have the flexibility to make its expertise in DSM available in the electric Conservation and Demand Management (CDM) arena. It also stated that it was not planning to engage in CDM consulting. Union stated that it does not plan to engage in electric CDM. However, Union supported EGD’s submissions.

SEC stated that on the assumption that the utilities can engage in electric CDM activities under the Undertakings given to the Lieutenant Governor in Council (the “Undertakings”), it supported the idea that the gas utilities be able to do joint programs with the electric LDCs, as this would tend to lower costs for the gas utilities. SEC cautioned against diverting the gas utilities' attention from gas DSM programs to electric CDM since the latter is, in SEC's view, more lucrative. CCC noted that there is no like thinking by the two utilities on their role regarding DSM activities and that there is no necessary and rational connection between electricity CDM and the utility DSM programs; therefore, there is a need to impose some constraints on the utilities' activities. CCC also questioned the legality of the gas utilities engaging in these activities without proper dispensation under the Undertakings. GEC submitted that gas utilities should only engage in electric CDM when it enhances gas DSM; otherwise, it would be a competing demand on scarce resources and a distraction from their primary focus. VECC supported co-delivery of DSM and CDM measures as it would reduce program costs, but not on the basis of incremental costing and profit sharing. LPMA and VECC suggested that electric CDM should be considered a non-utility activity for revenue requirement purposes of the distribution business.

EGD responded that it does not need an order or dispensation from the Board to engage in electric DSM. It specifically noted that gas DSM itself already generates electricity TRC savings which are included in the SSM calculations. EGD also stated that CDM is consistent with the objectives set out in the Ontario Energy Board Act to promote energy conservation; the Act does not limit the objective to simply natural gas. Further, this matter was canvassed in the EGD's EB-2005-0001 rate case where the Board approved the 50/50 earnings sharing mechanism for the joint participation in the TAPS electric CDM program.

The Board considers that the regulatory construct in Ontario is the concept of a pure distribution utility. This is manifested in the Undertakings and in the Board's rulings for some time. Gas DSM has remained an activity within the corporate structure of the utility and there is no compelling reason to alter this at this time - neither the utilities nor the intervenors instigated or sought a change with respect to gas DSM.

Recent developments in electric CDM may likely bring opportunities for gas utilities to engage or enhance engagement in this area. EGD has some minor engagements with Toronto Hydro Electric Systems Limited ("THESL"). Union does not appear to have any immediate plans to enter the electric CDM field. EGD, however, is interested in possibly expanding its electric CDM role where it is appropriate to do so.

There appears to be strong support if not consensus that the gas utilities should be permitted to engage in electric CDM if such engagement brings about cost efficiencies and the clear focus of the utility's demand management activities should relate to gas. The concern that attention may be diverted from gas DSM to electric CDM is, in the Board's view, theoretical at this stage. It is not axiomatic that enhanced engagement in electric CDM by the gas utilities will necessarily result in lost opportunities for gas DSM. The two initiatives can co-exist in an optimal and workable fashion. This is especially the case where demand management involves funding initiatives, not infrastructure, which has been the experience thus far.

The Board therefore is not concerned about the gas utilities in their present corporate structure engaging in electric CDM as long as such activities can be reasonably viewed as complementary and ancillary to gas DSM and do not involve investments in infrastructure. An example of that is EGD's involvement with THESL in the TAPS program. In fact, the utilization of the demand management expertise residing in the gas utilities should be viewed positively from a public interest perspective given the well known challenges in the Province's electricity sector. In that regard, engagement by the gas utilities in programs aimed at switching from electricity to gas is encouraged.

The concern arises if the gas utilities undertake stand-alone electric CDM activities. That is, programs that are not or do not appear to be synergetic to or enhancing gas DSM, especially if they involved investments in infrastructure on account of electric CDM. This would alter the regulatory construct of a gas distribution utility which would necessitate a review under the Undertakings and the Board's regulatory policies.

The Board is hampered in its assessment of the appropriate role for gas utilities in these situations. The Board is concerned about granting what might be viewed as blanket approval for the utilities to engage in electric CDM activities without knowing exactly what types of activity this might entail. For example, it is not clear if the gas utilities would bid for participation in the recently announced $400 million in OPA funding for electric CDM programs. As noted, the Board would not be concerned about gas utility involvement in OPA-funded programs targeted at switching from electricity to gas. The Board's concerns are in connection with stand-alone electric CDM programs where the gas utilities take on a central role.

This leads to the issue of whether relief from the Undertakings is required for the utilities to engage in electric CDM. EGD's current CDM activities with THESL were approved in EGD's most recent rates case. This program, however, is clearly incidental to EGD's DSM activities and it does not entail a separate infrastructure. EGD is free to continue its relationship with THESL regarding the TAPS program, and either gas utility may engage in similar programs with other electric LDCs where the CDM activity is clearly incidental to the utilities' DSM activities, or to engage in electric CDM stand-alone programs aimed at switching from electricity to gas where no dedicated investment in electric infrastructure would be required.

However, it is certainly possible that some other electric CDM activities or programs would require relief from the Undertakings. The Board is not in a position to articulate these engagements. The Board has not heard sufficient evidence to determine what would be an appropriate involvement by the gas utilities in such circumstances. The Board will leave it to the utilities to make such proposals if they so wish when they come forward with their respective DSM plans.

What is the appropriate treatment of costs and revenues for electric CDM? (Issue 15.2)

and

What incentives, if any, should be paid for electric CDM activities? (Issue 15.3)

There was no settlement (complete or partial) on these issues.

The utilities proposed that the costing of electric DSM should be on an incremental basis and the net revenues be split 50/50 between shareholders and ratepayers. This is the current practice for the TAPS program between EGD and THESL which was approved in the EB-2005-0001 rate case decision.

Some intervenors argued for full costing on the basis that it would avoid concerns about cross-subsidy between gas and electricity ratepayers. Full costing would also lower the net revenues to be split, thereby reducing the utilities' incentive to divert resources from DSM to CDM activities that may be more lucrative.

The Board notes that there was no opposition by intervenors to the institution of the 50/50 net revenue split proposal. The Board accepts the proposal as reasonable.

The utilities' proposal to use incremental costing is not acceptable to the Board. Full costing has been the general practice for programs that are not part of the core utility business and the Board sees no reason to deviate from that practice in this case. Full costing avoids cross-subsidization from gas to electricity ratepayers and reduces the incentive to shift resources from gas DSM to electric CDM in pursuit of possibly more lucrative returns in the latter.

Having approved the incentives contained in the "financial package", the Board does not see the need for other incentives necessary or appropriate for gas utilities to engage in electric CDM activities at this time.

CHAPTER 5 – INPUT ASSUMPTIONS, COMMON GUIDE, AND NEXT STEPS

In this chapter the Board addresses Issue 3.2 which is whether there should be a common guide to specify what input assumptions should be used by the utilities, and deals with the next steps of this proceeding.

Prior to and during the oral hearing the Board indicated that the process of listing and valuing input assumptions would not be part of this phase of the proceeding and that the Board wished to hear from parties on the appropriate subsequent process.

Issue 3.2 was phrased as, should there be a common guide (e.g. TRC Guide for Conservation and Demand Management ("CDM")) to specify what input assumptions should be used by the utilities?

All intervenors agreed as follows:

> "No. The input assumptions should be included in each utility's plan, and should be updated for each Utility during the plan period in accordance with the partial settlement to issue 3.1."

The utilities endorsed the notion of a common list and common values (where appropriate) of input assumptions for the two utilities in a common document. They suggested that this document would be an appendix to a Guide document which would reflect the Board's decision and convert elements of the decision into an operational handbook. They argued that this would be consistent with the intent of the proceeding to develop a rules-based framework for DSM. The utilities further suggested that Board Staff could take ownership of the development of the Guide and become the custodian for future updates.

The utilities argued that the creation of a common document has several advantages. Many of the input assumptions are common and they could be updated in their entirety by a Board process every three years. There would be no question as to the input assumptions that the utilities are to use. Assigning Board Staff the responsibility of updating the input assumptions would impart discipline on parties seeking to change the input assumptions. The utilities noted that where there was a need for different input assumptions between EGD and Union, it would not be difficult to effect within the list.

SEC argued that common input assumptions was a non-issue since the process for amending and updating the assumptions is completely settled in issues 3.1, 3.3 and 3.4 and that the existence of a guide is not relevant to the inclusion or determination of input assumptions. GEC endorsed SEC’s view and further argued that an input assumptions process may frustrate the settlement on those issues. GEC further suggested that the Board should rely upon the evaluation and audit process to consider input assumptions. Energy Probe endorsed the submissions put forward by GEC and SEC. LPMA submitted that each utility should include its input assumptions as part of its own plan but the utilities should work together to develop common input assumptions where appropriate. Some argued that translating the Board’s decision into a guide amounted to a waste of time, and unless the Board drafted the Guide and handed it to parties in a finished version, parties would take the opportunity to re-argue issues in interpreting the Board’s decision.

In the Board’s view it is clear that TRC input assumptions will have to be determined before any DSM plans can be finalized. The Board also agrees that the process should be conducted under the Board’s review as a second phase to the current proceeding. The Board feels that the most appropriate process for creating the input assumptions guide is one similar to that employed to create the CDM Handbook. The Board therefore directs Board Staff to circulate a draft of an input assumptions guide. Parties will be given an opportunity to comment on the draft and, where they feel it necessary, to make submissions for changes with appropriate support. A Procedural Order will be issued which will set out the details of this process more fully. It is anticipated that this second phase to the proceeding will be completed before the end of 2006.

There are no persuasive reasons in the Board's view not to have a common list of input assumptions and common values with the exceptions of the values as noted in this decision. In fact it appears to the Board that there are efficiencies to be gained by the use of a common set of assumptions. To the extent that there may be differences in how the assumptions might apply to the two utilities or in the values themselves as allowed in the decision, these could be accommodated and highlighted within the generic set. There are only two gas utilities affected and it would not be administratively difficult to do so.

Once the initial list and measures of the input assumptions is determined, the issue then becomes: what is the process for updating these?

The completely settled issue 3.1 stipulates that the input assumptions will be updated on a regular basis during the plan period as part of each utility's ongoing evaluation and audit process. The Board has the ultimate authority to review and approve any changes. It appears to the Board that unless there is joint utility participation, the updates may occur at different times. This would not be efficient and would burden the regulatory process needlessly. The Board therefore concludes that the updating process should be centralized within Board Staff, at least for this first generation of multi-year DSM plans. The Board anticipates that the recommendations that come from the evaluation and audit committee would, in effect, be the substance of the comments process to be employed for the updating of the list and values of the input assumptions. Any suggested updates to the input assumptions guide arising from the evaluation and audit process should be filed with the Board within one month of the end of the annual audit and evaluation. The suggested updates will be considered by the Board, and the guide will be updated if the Board decides it is necessary. Further Procedural Orders may be issued regarding updates to the guide.

The next issue is whether there should be a handbook.

While the Board sees the merits in having a stand-alone handbook, it has concluded that this initiative should not be undertaken at this time. In making this finding, the Board is cognizant of the time sensitivity and significant effort that will be required to develop the common list and measures of the input assumptions and the Board does not wish parties be distracted by the effort to develop a handbook at this time.

The Board will issue a Procedural Order commencing the next phase that will lead into the determination of the input assumptions. The role of Board Staff will be set out in that procedural order. Further Procedural orders will be issued as required from time to time for the Board to receive and rule in this matter and to cause the filing of the multi-year DSM plans by the utilities.

Intervenors eligible for cost awards shall file their cost claims by September 15, 2006. The utilities may comment on these claims by September 22, 2006. The cost award applicants may respond to the utilities' comments by September 29, 2006. Union and EGD shall pay in equal amounts the intervenor costs to be awarded by the Board in a subsequent decision, as well as any incidental Board costs.

Dated at Toronto, August 25, 2006

Original Signed By

Pamela Nowina
Presiding Member and Vice Chair

Original Signed By

Paul Vlahos
Member

Original Signed By

Ken Quesnelle
Member

APPENDIX 1

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0021

PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

THE PROCEEDING

On February 15, 2006, the Board issued a Notice of Application that was published.

The Board issued Procedural Order No.1 on March 2, 2006, establishing the procedural schedule for all events prior to the oral hearing. These events included:

- EDGI and Union evidence filed by April 10, 2006;
- Issues conference on April 24, 2006;
- Issues Day on April 28, 2006;
- Technical Conference to replace interrogatories on EDGI and Union's evidence on May 11 and 12, 2006;
- Intervenor (non-utilities) evidence filed by June 1, 2006;
- Technical Conference to replace interrogatories on Intervenor (non-utilities) evidence on June 8, 2006;
- Half day Intervenor Conference on June 19, 2006;
- Settlement Conference beginning June 19, 2006;
- Settlement Proposal by June 28, 2006; and
- Board review of Settlement Proposal on July 6, 2006.

In response to Procedural Order No. 1, the Board received written evidence prepared by the following parties:

- Malcolm Rowan on behalf of Canadian Manufactures and Exporters ("CME");
- Paul Chernick on behalf of the School Energy Coalition ("SEC");
- Chris Neme on behalf of the Green Energy Coalition ("GEC"); and
- Roger Colton on behalf of Low Income Energy Network (LIEN").

On April 28, 2006, the Board issued Procedural Order No. 2, which established the Issues List for the proceeding.

On June 12, 2006, Procedural Order No. 3 was issued as a result of there not being adequate time to complete the questions on CME evidence within the one day Technical Conference. The Board ordered CME to provided written responses to SEC and GEC questions.

Procedural Order No. 4, issued June 28, 2006, provided the parties with an extension to file a Settlement Proposal with the Board.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board's offices.

Union Gas Limited ("Union")	Crawford Smith
Enbridge Gas Distribution ("EGD")	Dennis O'Leary
Board Counsel and Staff	Michael Millar Michael Bell Stephen McComb
Canadian Manufacturers & Exporters ("CME")	Brian Dingwall

Consumers Council of Canada (“CCC”)	Robert Warren
Energy Probe	Norm Rubin
Green Energy Coalition (“GEC”)	David Poch
Industrial Gas Users Association (“IGUA”)	Vince DeRose
London Property Management Association (“LPMA”)	Randy Aiken
Low Income Energy Network (“LIEN”)	Juli Abouchar
Pollution Probe	Murray Klippenstein
School Energy Coalition (“SEC”)	Jay Shepherd
Vulnerable Energy Consumer’s Coalition (“VECC”)	Michael Buonaguro

WITNESSES

There were 11 witnesses who testified at the oral hearing. The following EGD and Union employees appeared as witnesses at the oral hearing:

EGD

Susan Clinesmith	Manager, Business Markets
Norman Ryckman	Group Manager, Business Intelligence and Support
Michael Brophy	Manager, DSM and Portfolio Strategy
Patricia Squires	Manager, Mass Markets and New Construction Market Development

Union

Chuck Farmer	Director, Market Knowledge and DSM
Tracy Lynch	Manager, DSM

In addition, EGD called the following witness:

Dr. Daniel M. Violette	Principal and Founder, Summit Blue Consulting

Witnesses called by intervenors at the oral hearing:

Chris Neme (By GEC)	Director of Planning and Evaluation, Vermont Energy Investment Corporation
Malcolm Rowan (By CME)	President, Rowan and Associates Inc.
Roger D. Colton (By LIEN)	Consultant, Fisher, Sheehan & Colton

In addition, CME called the following witness:

Anthony A. Atkinson	School of Accountancy, University of Waterloo

Attachment 84.1

DSM HANDBOOK

A DSM HAND BOOK FOR ONTARIO NATURAL GAS LOCAL DISTRIBUTION COMPANIES

APRIL 10, 2006

Table of Contents

Background

This Handbook has been prepared to assist natural gas local distribution companies (utilities) in meeting the filing requirements associated with their Demand-Side Management (DSM) programs. This Handbook sets out the regulatory framework and provides "prescriptive" rules and the basic requirements related to planning, delivering and evaluating DSM program offerings, with particular focus on the planning and evaluation elements. This Handbook will form the basis for natural gas utilities' DSM activities starting in 2007 and is expected to be used until reissued by the Ontario Energy Board.[1]

The development of prescriptive rules that can be applied across utilities and programs is applied because it provides some degree of consistency in approach between the utilities and serves to reduce the regulatory burden of DSM for all parties.

The original set of Guidelines that the natural gas utilities operated their DSM efforts under were laid out in EBO 169. This Handbook represents an update to EBO 169 and builds on the various arrangements and resolutions made through subsequent Board Decisions and proceedings. The development of this Handbook started with an examination of the various issues identified in the Board Procedural Order No. 1[2] (termed the Issues List hereafter) and extended that examination to include other issues that are relevant to DSM.

The structure of this document generally follows the categories as presented in the Issues List:

Section 1 identifies the specific filing requirements needed for Board approval of the utilities' DSM activities.

Section 2 highlights the DSM Plan requirements.

Section 3 examines cost effectiveness and screening requirements for a DSM portfolio. It includes a discussion and description of the Total Resource Cost Test (TRC) test and the various inputs and components that make up the test.

Section 4 introduces the common DSM planning guide to be used by natural gas utilities in Ontario, including standardized assumptions and inputs for undertaking the TRC test.

---

[1] Changes to assumptions or amendments to multi-year plans are to be done within the rules established by this Handbook.
[2] "Natural Gas Demand Side Management Generic Issues Proceeding Procedural Order No.1", Board File No. EB-2006-0021

Section 5 examines the requirements for establishing and clearing lost revenues through the Lost Revenue Adjustment Mechanism (LRAM).

Section 6 examines the requirements for establishing an incentive through the Shared Savings Mechanism (SSM).

Section 7 examines the requirements for using and clearing the Demand-Side Management Variance Account (DSMVA).

Section 8 examines the requirements for using and clearing the Electric Program Earnings Sharing Deferral Account (EPESDA).

Section 9 outlines the use of the stakeholder consultation process.

Section 10 identifies research requirements in support of DSM activities.

Section 11 examines the expected evaluation requirements and report(s) and the use and role of the third party Auditor.

Section 12 discusses how market transformation and lost opportunity programs are integrated into the DSM activities, including the nature and focus of program design and evaluation requirements.

Section 13 examines attribution and identifies rules for sharing claimed results when there are multiple parties (both regulated and non-regulated) delivering the programs. This section also outlines the role and ability for utilities to provide program delivery for external parties such as electric LDCs.

1. Ontario Energy Board Approval

The Ontario Energy Board (OEB) approves activities associated with natural gas utility delivery of DSM. The following DSM framework provides a more efficient and streamlined role for all Stakeholders including the OEB. In this framework, the role of the Board consists of approval of key elements of the utilities' multi-year plans and results, including:

- budgets;
- cost effectiveness of the plans;
- avoided costs;
- measures assumptions not previously approved;
- DSMVA, SSM, LRAM and EPESDA[3] claims; and
- account clearance.

Table 1 shows the various aspects of Board input to the process. Each component is discussed in detail in the following sections. The framework shall follow the rules as approved by the Board in the EB-2006-0021 proceeding.

Table 1: Components of DSM for OEB Approval

	DSM Multi-Year Plan	Annual
Budgets	✓	
Plan Measure Assumptions	✓	
Portfolio TRC Test Results	✓	
Avoided costs	✓	
Measure assumptions not previously approved in the Handbook		✓
LRAM, SSM, DSMVA, and EPESDA approval for clearance		✓

[3] Electric Program Earnings Sharing Deferral Account as approved in EB-2005-0001.

2. DSM Plan Requirements

DSM Plans will be based on a multi-year planning horizon. The term of the Plan shall be for the duration of the incentive regulation term, if possible, but not less than 3 years. This approach represents best practice for DSM planning in North America.[4] As shown in Table 1, certain aspects of a multi-year plan require Board approval.

The following defines the terms used in Table 1.

Budget Setting: Budgets shall be established by the utility, having regard to utility-specific circumstances, including programming needs, research and evaluation requirements and regulatory engagement. A bottom-up approach to Plan development is appropriate.

Measure Assumptions: Utilities shall apply to the Plan all key assumptions regarding savings, costs, free ridership and equipment life as defined in Appendix A. This information has been provided in the form of a standardized "Measures List", similar to that used by the electric LDCs in Ontario.[5] Measure assumptions for new programs are to be submitted to the Board on an annual basis, if required.

TRC Test Results: Utilities shall calculate and report the anticipated TRC results for the portfolio, based on standard assumptions regarding costs and benefits. See Section 3.

Avoided Costs: Utilities shall submit updated avoided cost estimates, including relevant documentation and rationale for use in the DSM Plan. See Section 4.

LRAM: The LRAM is a rate adjusting mechanism that captures the increase or decrease in a utility's distribution margin due to the utility either underachieving or overachieving the DSM volumetric savings estimate included in rates for the first year of program implementation.

SSM: A Shared Savings Mechanism (SSM) is a financial tool that allows utilities and customers to "share" in the societal benefits that successful DSM programs generate. SSM can include both Resource Acquisition and Market Transformation incentives.

DSMVA: The existence and use of a DSM variance account provides a degree of flexibility for utilities as they undertake DSM investment. A DSM variance

---

[4] The Canadian Gas Association identified a multi-year approach to planning as a best practice for DSM: "Canadian Natural Gas Distribution Utilities" Best Practices in DSM, IndEco Strategic Consulting and b. Vernon & Associates for Canadian Gas Association, 2005, pg 30.
[5] Ontario Energy Board, September 8, 2005. "Total Resource Cost Guide".

account may be used to rebate ratepayers at year end for unused budget allocation or to recover from ratepayers additional costs incurred for DSM programs.

EPESDA: The EPESDA is used to record half of the net revenue earned by a utility through delivering programs on behalf of an external party such as an electric LDC.

3. Screening of the DSM Portfolio

Background: DSM investments must be examined for their cost effectiveness, based on a methodology that provides similar economic evaluation to supply side investments. In practice, this cost effectiveness examination typically relies on a test known as the Total Resource Cost Test (TRC). EBO 169 established the TRC test as the key hurdle test for DSM investments by natural gas utilities. The application of this test has been affirmed for use by electric LDCs by the Ontario Energy Board through the publication of the "Total Resource Cost Guide".[6] Users of this Handbook are encouraged to review the Total Resource Cost Guide for a comprehensive discussion of the components of the TRC Test.

The TRC test is defined as a test that "measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant's and the utility's costs".[7] The TRC test measures the benefits and costs of DSM investments from a societal perspective. Under the TRC test, benefits are driven by avoided resource costs. Costs in the TRC test are the costs of the energy efficient equipment and the utility program support costs associated with delivering the equipment to the marketplace.

As indicated, the TRC Test examines streams of benefits and costs and uses discounting principles to express these future values as a single number. The NPV_{TRC} formula is as follows:

$$NPV_{TRC} = B_{TRC} - C_{TRC}$$

where;

[6] IBID.
[7] California Public Utilities Commission, (2001) Standard Practices Manual: Economic Analysis of Demand-Side Management Programs and Projects.

$$B_{TRC} = \sum_{t=1}^{N} \frac{AC_t}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t}{(1+d)^{t-1}}$$

and;

B_{TRC} = The benefits of the program

C_{TRC} = The costs of the program

AC_t = Avoided costs in year t

UC_t = Program costs in year t

PC_t = Participant cost in year t

d = Societal discount rate

As shown, the benefits stem from resource costs that are avoided. The costs that are included are the cost of the energy efficient equipment and the utility program costs. Subtracting the costs from the benefits provides the net benefits. For a program to be considered cost effective, the net benefits must be greater than zero.

Use of the TRC Test: The TRC test is the sole test of cost effectiveness for programs and will be used for screening the portfolio of programs. The utilities will ensure that the entire portfolio has a positive net TRC. The utilities may reserve the right to invest in individual technology or program offerings that do not have appositive net TRC, if the utility believes there are compelling reasons to do so.

Due to the unique characteristics of market transformation programs they shall not be included in the Plan portfolio TRC test and shall be assessed separately. For these programs, utilities will develop metrics specific to the program, which will be approved by the Board (see section 12).

4. Assumptions and Inputs

Common Planning Guide: Input assumptions for unit measure savings for prescriptive measures, and for incremental equipment costs, measure life, and free ridership assumptions for both prescriptive and custom programs will be established for the entire planning horizon. These are common assumptions across the gas utilities. Updates to these assumptions that may arise based upon research or new information will be used only on a prospective basis (i.e. for the next multi-year Plan). Similar to the Measures List maintained by the OEB as part of the Total Resource Cost Guide[8] for electric LDCs, the Board will also maintain an official list of assumptions for the natural gas utilities. A list of measure and program assumptions is provided in Appendix A.

Custom Projects. Custom projects are those projects where a utility facilitates the implementation of specialized equipment and technology not identified in the Measures Assumption tables in Appendix A. Savings for these project are to be calculated on a project specific basis and a free ridership of 30% is to be used in calculating net savings.

Avoided costs, Background: The TRC Test assesses DSM costs and benefits from a societal perspective. The benefits are defined as “avoided costs”. This represents the benefit to society of not having to provide an additional unit of supply. Avoided costs exist for all resources, including natural gas, electricity, oil, water, etc. Certain DSM programs will provide reductions in the use of these other resources and while these savings may not be the primary target of the program, it is appropriate to include these savings in the TRC analysis.

The TRC test requires an analysis over the life-cycle of the DSM measure. As such, long-term projections of avoided costs are required. As well, any DSM measures that are included in the analysis must have equipment life estimates along with the estimates of the savings and the costs.

Avoided costs are calculated using detailed projections of system load configurations and expected use. Utilities will calculate, report, and use new sets of avoided costs (natural gas, electricity and water) in preparation for the multi-year Plan submission, based on market values.

Avoided costs, Natural gas: For natural gas, supply costs include transportation, distribution, storage, and commodity costs. The utilities shall use a common methodology for calculating these costs. This shall include market values for commodity costs and utility specific transportation, distribution and storage costs.

All assumptions outlined in the Handbook are to be applied in the manner outlined in Table 2.

[8] IBID

Table 2
Treatment of DSM Input Assumptions for the Purpose of Calculating SSM, LRAM and DSMVA

Measure Input Assumptions						
Program Type	Participants	Annual Unit Savings	Free Rider %	Measure Life	Unit Incremental Costs	Direct Program Costs
Prescriptive	Actual	Fixed	Fixed	Fixed	Fixed	Actual
Custom	Actual	Actual	Fixed	Actual	Actual	Actual

5. Lost Revenue Mechanism (LRAM)

Background: The LRAM is a rate adjusting mechanism that captures the increase or decrease in the utility's distribution margin due to the utility either underachieving or overachieving against the DSM volumetric savings estimate included in rates.

The LRAM is intended to compensate utility shareholders for margins lost as a result of greater than anticipated DSM performance and conversely, compensates ratepayers for any amounts built into rates where the utility does not meet the volumetric savings estimate that was included in rates.[9]

Approach: The calculation of actual volumes saved for the purposes of LRAM will be based on assumptions approved in the Plan. Improved savings assumptions shall only be used on a prospective basis. For a multi-year plan, prospective use means for use in the next multi-year plan. The actual savings that are used are those that are provided as part of the annual Evaluation Report (and Audit). Calculation of the first year impact of lost volumes on distribution revenues are to be calculated as 50% of the total annual savings and at 100% for each subsequent year. This reflects the average savings impact of measures that are implemented over the course of a full year.

The LRAM is to be calculated, reported and cleared annually as part of the annual evaluation and reporting efforts.

Independent Auditor: An independent auditor shall review and verify the claimed volumetric and financial results.

[9] In EBRO 495, the Board directed Enbridge to implement the LRAM as proposed in the Settlement Agreement for 1998 and described in the DSM Plan, EBRO 495, Ex 2, Tab 6, Sch 1, page V-4.

Rate Allocation: Rate changes that are a result of the change in distribution revenue due to the DSM programs will be allocated to the rate classes where the DSM volume reductions originated. Once the LRAM amounts have been verified by the Auditor and approved for clearance, they will be assigned to the various rate classes based on the volumes saved in the rate class.

6. Shared Savings Mechanism (SSM)

Background: A Shared Savings Mechanism (SSM) is a financial tool that allows utilities and customers to "share" in the societal benefits that successful DSM programs generate. The utility is thus rewarded for its delivery of services and programs to reduce energy use and is able to achieve a return on its human capital investment.

The SSM is an effective mechanism to encourage utilities to make resource and managerial commitments to optimize their DSM offerings. Shared Savings mechanisms are considered separately for resource acquisition programs and market transformation programs.

Resource Acquisition Programs: The resource acquisition Shared Savings Mechanism will be based on the TRC net benefits resulting from program implementation. The SSM calculation uses an increasing simple percentage of net TRC outcome based upon actual results. This is shown in Table 3 below.

Table 3: SSM Mechanism

TRC ($mm)	% Payout	Incremental %
1 to 50	1.5%	1.5%
>50 to 100	4.0%	2.5%
>100 to 150	7.5%	3.5%
>150 to 200	12.0%	4.5%
>200	17.5%	5.5%

Market Transformation Programs:
A Market Transformation ("MT") incentive that addresses the unique characteristics of MT while ensuring that MT efforts maintain an equal footing with Resource Acquisition programs is required.

The incentive model shall assume that MT programs result in equivalent TRC benefits per dollar spent as the Resource Acquisition programs in the utility's portfolio. Further, in order to compete with Resource Acquisition spending, MT programs are to be incented at the highest marginal incentive rate achieved by the Resource Acquisition programs as defined above.

The incentive model shall use the product of the MT spending for the year and the actual DSM portfolio (resource acquisition) TRC net benefits/cost ratio times the percentage of the highest marginal incentive rate achieved for the resource acquisition portfolio of programs.

For example, assume

- A DSM portfolio of resource acquisition programs had a net TRC benefit of $150 million based on expenditures of $20 million in O&M.
- The portfolio had a TRC net benefits cost ratio of 7.5:1, or simply stated, for every dollar spent $7.50 of benefits resulted.
- The Resource Acquisition SSM incentive rate for this level of benefit is 7.5%
- MT activities were undertaken during the year and the actual cost was $3 million.

The MT incentive calculation is as follows:

(NET TRC / O&M Spend) X (MT Spend) X (SSM Marginal Incentive Rate)
($150 million / $20 million) X ($3 million) X (7.5%)
7.50 X $3 million X 7.5%
= $1.7 million MT incentive

The utilities will submit a detailed description of Market Transformation programs as part of the multi-year DSM plans.

Independent Auditor: An independent Auditor will review and verify results and the claimed SSM for both resource acquisition and market transformation programs.

Rate Allocation of Incentives: Incentive amounts that result from the operation of DSM programs will be assigned to the rate classes in proportion to the TRC net benefits received by the rate classes. Where TRC net benefits can not be defined across rate classes, the incentives are to be assigned in the same manner as program costs.

7. Demand-Side Management Variance Accounts (DSMVA)

Background: The existence and use of DSM variance accounts provides a degree of flexibility for utilities as they undertake DSM investment. A DSM variance account may be used to rebate ratepayers at year end for unused budget allocation or to recover from ratepayers additional costs incurred for DSM programs.

Rate Allocation: DSM costs are assigned to the rate classes that benefit from the operation of the programs. Similarly, variance expenditures that occur as a result of the operation of DSM programs will be assigned to the rate classes based on the rate class contribution to the variance.

DSMVA Clearance: The DSMVA is not subject to the DSM audit. Clearance of the DSMVA is done as part of the standard financial operations of the utility.

8. Electric Program Earnings Sharing Deferral Account (EPESDA)

Electric DSM program delivery - There is an opportunity for gas utilities to provide program services to another entity such as an electric LDC. All incremental electric program costs beyond a natural gas utility's traditional portfolio of programs shall be recovered through partnerships with electric LDCs so as to not impact gas ratepayers. The utilities shall share with Ratepayers, on an equal basis, any net revenues achieved through these program activities.

The EPESDA is used to record half of the net revenue earned by the utility delivering programs on behalf of an external party such as an electric LDC. On clearance of the account at year end, 50% of the net revenue is returned to ratepayers and the remaining 50% is distributed to the utility's shareholders.

9. Stakeholder Consultation

The primary purpose of stakeholder consultation is to provide value added insights and guidance with respect to the effectiveness of the DSM investment or related issues. This includes program breadth, direction and characteristics, success factors and stakeholder/customer perspective. While the utilities are solely responsible and accountable for their DSM efforts and are not mandated to undertake consultations, there may be merit, in certain situations, in seeking input and guidance from stakeholders, industry partners and customers.

The utility, which is ultimately responsible and accountable for its DSM program must decide the degree to which it involves stakeholders in the development and operation of its DSM program. Stakeholder input is desirable but is not mandatory. The utilities are encouraged to pursue stakeholder engagement where it can provide greater efficiency and effectiveness.

10. Research

As part of their development and planning process, utilities should undertake research in support of both planning assumptions and to develop new information with input from the Board, stakeholders and other interested parties. Due to the variation by utility and by year, efforts per year or per planning cycle should be included within budgetary considerations established as part of the multi-year plan. The utilities shall determine the research requirements with the context of their overall DSM plans.

There may be opportunities to combine or share research efforts with other utilities. These should be explored where possible in an effort to reduce duplication. Utilities are encouraged to share their research plans where possible to make it known where opportunities for synergies may exist.

11. Evaluation and Audit

Background: Evaluations of DSM activities are typically undertaken to document and support savings and costs (impact evaluations). In addition, to identify future programming needs, research requirements, and potential new or unexpected barriers and/or opportunities, several types of evaluations are used, including impact and process evaluations as well as research supporting program assumptions.

Impact evaluation and audits are important elements in the determination of SSM, LRAM and the clearance of variance accounts. The documentation and verification component lends itself to an annual process using prescriptive guidelines, while other types of program evaluation can be done as required. The following proposition considers only impact evaluation needs.

Principles – Role of the Utility: Documentation and verification activities are developed under the following principles:

- The utility is responsible and accountable for the evaluation and audit process; and
- The utility shall decide the focus of the evaluation work and the associated budget.

An annual report will provide:

- Details of the program results (See Appendix B for Reporting templates); and
- The annual SSM, DSMVA and LRAM calculations.

Third Party Audit: The role of the Auditor shall focus on validation of the savings and costs with respect to the SSM and LRAM claims in accordance with the rules prescribed by the Board.

12. Market Transformation, Lost Opportunity Programs and Program Funding

Market transformation is defined as "A reduction in market barriers due to a market intervention, as evidenced by a set of market effects that last after the intervention has been withdrawn, reduced or changed."[10] Market transformation programs are inherently different than typical resource acquisition programs as their focus is shifted towards more upstream channel participants and there is often less reliance on the use of incentives paid to participants or customers. Ultimately, their goal is to increase the market share for energy efficiency products such that the market is transformed. This transformation is often accompanied by a code change that seals in the improved efficiency level (note that utilities may wish to participate in Code discussions as part of the program support).

Measuring the impacts of market transformation programs is more complicated than that of traditional programs, particularly in the absence of incentives. Market transformation evaluation typically relies on the use of "near" and "distant" indicators and measures, all of which require both base-line estimates and on-going tracking. It is also important to establish the indicators as part of the design of the program and to build in processes that ensure appropriate monitoring.

Determining when and how to use market transformation programs requires a solid understanding of market dynamics and the potential. Ideally, this is done on a case by case basis where it is understood that some opportunities will inherently lend themselves to market transformation efforts.

Lost opportunity programs are those that focus on markets where the opportunity to make change is likely only to occur once or very infrequently. This would apply well to the new construction sectors where once energy use decisions are made; they are unlikely to be re-visited for many years. Utilities are encouraged to operate programs that address these lost opportunities to optimize the long term impact of DSM.

[10] EB-2005-0001 Exhibit A7, Tab 3, Schedule 1

Program Funding*.* Market transformation and lost opportunity funding shall be based on the specific program goals and needs as identified by the utility in its multi-year plan.

13. Attribution of Benefits

Partnerships with Regulated LDCs (i.e. regulated by the OEB). For partnerships between OEB regulated entities, benefits will be allocated based on a negotiated agreement. Where such an agreement does not exist, the rules of the TRC Guide[11] will apply. Attribution assumptions made when the Plan is approved must remain constant when the results are assessed.

Partnerships with non-regulated entities. Utilities shall claim savings subject to the rule recently established by the Board in the EB-2005-0001 Partial Decision.

> *"the Company may claim 100 percent of the benefits associated with DSM programs in which it plays a central role in the marketing and delivery of the program with a non-rate-regulated third party." (p. 8)*

The Board also approved the definition of "central role" in the EB-2005-0001 Partial Decision:

> *"In the Company's view it should be considered to have played a central role in a program if it initiated the partnership, initiated the program, funded the program, or implements the program." (p. 7)*

Attribution shall be established at the time that a multi-year plan is developed and approved. Any changes to these values are to be applied prospectively for the next multi-year plan.

Delivery of Electric Programs for Third Parties (e.g. LDCs). LDCs shall be able to enhance Ontario's Conservation Culture and results through delivering cost-effective programs as outlined in Section 8 of this Handbook. Attribution of benefits will be dealt with within the contracts established between these parties.

In areas where LDC partnerships are not developed, the natural gas utilities shall continue to attempt to enhance electrical benefits associated with existing

[11] IBID

programs and should include any of the incremental benefits that can be demonstrated and substantiated in its actual results.

Appendix A: Measure Assumptions

RESIDENTIAL

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions: Natural Gas m3	Resource Savings Assumptions: Electricity kWh	Resource Savings Assumptions: Water L	Equipment Life Years	Incremental Cost: Customer Installed	Incremental Cost: Contractor Installed	Free Ridership %
NEW CONSTRUCTION									
Basement Insulation (R-12)	OBC basement insulation levels	weather	93	-	-	25	-	$700	0%
Energy Star Home	Home built to OBC	weather	800	1,000	-	25	-	$3,020	0%
High Efficiency Furnace	Mid-Efficiency Furnace	weather	226	-	-	18	-	$647	30%
High Efficiency Integrated Appliance	Mid-Efficiency Furnace / Storage Tank Water Heater	weather	287	-	-	18	-	$850	0%
EnerGuide for New Houses	Home built to OBC	weather	450	0	0	25	-	$2,000	0%
Programmable Thermostat	Standard Thermostat	weather	172	200	-	18	-	$65	30%
R-2000	Home built to OBC	weather	800	0	0	25	-	$4,000	0%
Tankless Water Heater	Storage Tank Water Heater	base	206	-	-	20	-	$650	0%
Two-Stage Furnace with ECM	Mid-Efficiency Furnace	weather	245	580	-	18	-	$1,563	30%
Waste Water Heat Recovery	No heat recovery	base	267	-	-	30	-	$625	0%

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions: Natural Gas m3	Resource Savings Assumptions: Electricity kWh	Resource Savings Assumptions: Water L	Equipment Life Years	Incremental Cost: Customer Installed	Incremental Cost: Contractor Installed	Free Ridership %
EXISTING HOMES									
Condensing Boiler - up to 299 Mbtu/h	Standard Boiler	weather	925	-	-	25	-	$1,300	0%
Condensing Gas Water Heater	Storage Tank Water Heater	base	203	-	-	9	-	$1,000	0%
Energy Star Clothes Washer	Standard Clothes Washer	base	55	31	28,731	13	-	$350	8%
Energy Star Window	Standard Window	weather	13	16	-	25	-	$52	20%
Enhanced Furnace	Mid-Efficiency Furnace	weather	320	730	-	18	-	$1,200	10%
Faucet Aerator	Faucet w/o aerator	base	17	-	7,592	10	$2	-	10%
Heat Traps	Storage Tank Water Heater w/o heat trap	base	73	0	0	10	-	$80	0%
High Efficiency Furnace	Mid-Efficiency Furnace	weather	385	-	-	18	-	$650	48%
Home Rewards w/o Program. Thermo	Existing Home Sample	weather	1,321	300	0	25	-	$2,708	8%
Low-Flow Showerhead	Average Existing Stock	base	134	-	27,634	10	$5	$15	10%
Pipe Insulation	Water Heater w/o pipe insulation	base	17	-	-	15	$1	$4	4%

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions: Natural Gas m3	Resource Savings Assumptions: Electricity kWh	Resource Savings Assumptions: Water L	Equipment Life Years	Incremental Cost: Customer Installed	Incremental Cost: Contractor Installed	Free Ridership %
EXISTING HOMES CONT'D									
Power Comb. Boiler - up to 299 Mbtu/h	Standard Boiler	weather	659	-	-	25	-	$500	51%
Programmable Thermostat	Standard Thermostat	weather	212	100	-	18	-	$65	11%
Tankless Water Heater	Storage Tank Water Heater	base	203	-	-	20	-	$650	0%
Two-Stage Furnace with ECM	Mid-Efficiency Furnace	weather	332	535	-	18	-	$1,563	30%
Waste Water Heat Recovery	No heat recovery	base	267	-	-	30	-	$625	0%

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions: Natural Gas m3	Resource Savings Assumptions: Electricity kWh	Resource Savings Assumptions: Water L	Equipment Life Years	Incremental Cost: Customer Installed	Incremental Cost: Contractor Installed	Free Ridership %
LOW INCOME									
Faucet Aerator	Faucet w/o aerator	base	17	-	7,592	10	$2	-	0%
Low-Flow Showerhead	Average Existing Stock	base	134	-	27,634	10	$5	$15	0%
Pipe Insulation	Water Heater w/o pipe insulation	base	17	-	-	15	-	$4	0%
Programmable Thermostat	Standard Thermostat	weather	212	-	-	18	-	$90	0%

COMMERCIAL

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions: Natural Gas m3	Resource Savings Assumptions: Electricity kWh	Resource Savings Assumptions: Water L	Equipment Life Years	Incremental Cost: Customer Installed	Incremental Cost: Contractor Installed	Free Ridership %
NEW BUILDING CONSTRUCTION									
Condensing Gas Water Heater	Storage Tank Water Heater	base	1,750	-	-	15	-	$4,200	5%
Rooftop Unit	Standard Rooftop Unit	weather	1,275	-	-	20	-	$1,250	0%
Programmable Thermostats	Standard Thermostat	weather	519	921	-	18	-	$65	11%
Tankless Water Heater	Storage Tank Water Heater	base	825	-	-	20	-	$2,200	0%

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions: Natural Gas m3	Resource Savings Assumptions: Electricity kWh	Resource Savings Assumptions: Water L	Equipment Life Years	Incremental Cost: Customer Installed	Incremental Cost: Contractor Installed	Free Ridership %
EXISTING BUILDINGS									
Condensing Gas Water Heater	Storage Tank Water Heater	base	1,750	-	-	15	-	$4,200	5%
Faucet Aerators	Faucet w/o aerator	base	17	-	7,592	10	$2	-	10%
High Efficiency Furnace	Mid-Efficiency Furnace	weather	385	-	-	18	-	$650	10%
Low-Flow Showerhead	Average Existing Stock	base	134	-	27,634	10	$5	$15	10%

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions			Equipment Life	Incremental Cost		Free Ridership
			Natural Gas m3	Electricity kWh	Water L	Years	Customer Installed	Contractor Installed	%
EXISTING BUILDINGS CONT'D									
Pre-Rinse Spray Nozzle	Average Existing Stock	base	2,434	-	432,800	5	-	$100	5%
Programmable Thermostats	Standard Thermostat	weather	519	921	-	18	-	$65	11%
Rooftop Unit	Standard Rooftop Unit	weather	1,275	-	-	20	-	$1,250	0%
Tankless Water Heater	Storage Tank Water Heater	base	825	-	-	20	-	$2,200	0%
Two-Stage Furnace with ECM	Mid-Efficiency Furnace	weather	332	535	-	18	-	$1,563	30%
Water Tank De-liming	Storage Tank Water Heater (with liming)	base	1,033	-	-	3	-	$150	0%

Appendix B: Annual Reporting Forms

Table B1, Actual Results by Program

Program	Program 1	Program 2	Program 3	Total Sector Programs
Total Actual Participants				
Actual M3 Savings (000's)				
Actual Annual kW.h Savings				
Actual kW Savings				
Actual Water Savings				
Actual Expenditure				
Net TRC				

Sector	Residential	Commercial	Industrial	Total All Programs
Total Actual Participants				
Actual M3 Savings (000's)				
Actual Annual kW.h Savings				
Actual kW Savings				
Actual Water Savings				
Actual Expenditure				
Cost/M3				
Net TRC				
Benefit/Cost Ratio				
TRC per $ Spent				

Attachment 85.1

SUMMIT BLUE
CONSULTING, LLC

RAP
REGULATORY ASSISTANCE PROJECT

DEMAND-SIDE MANAGEMENT: DETERMINING APPROPRIATE SPENDING LEVELS AND COST-EFFECTIVENESS TESTING

Prepared for:

Canadian Association of Members of Public Utility Tribunals
(CAMPUT)

January 30, 2006

Daniel Violette
Summit Blue Consulting
1722 14th Street, Suite 230
Boulder, CO 80302
720-564-1130
dviolette@summitlue.com

Richard Sedano
The Regulatory Assistance Project
50 State Street
Montpelier, VT 05602
802-233-8199
rapsedano@aol.com

TABLE OF CONTENTS

ACKNOWLEDGEMENTS

This study was made possible by the invaluable contributions of the following team members.

The Regulatory Assistance Project:	Cathie Murray
	Liz Baldwin
Summit Blue Consulting:	Gay Cook
	Randy Gunn

EXECUTIVE SUMMARY

The Canadian Association of Members of Public Utility Tribunals (CAMPUT) RFP listed seven items that would provide insights and information to lead to a reasoned approach for addressing the overall engagement objective: *"What is the appropriate level of spending on DSM and what are the best mechanisms to ensure the testing of costs/benefits with a view to adopting guidelines for use by utilities and regulators?"*

1. The present level of interest in DSM in Canada and the US and how this may vary between areas in which deregulation has occurred and those areas which are still served by vertically integrated utilities.

2. Is the interest in DSM mainly driven by government, utilities, regulators, or others?

3. For areas that are promoting DSM, what types of programs are being promoted, e.g., load shifting, conservation, interruptible load, etc.?

4. What types of tests are used to determine the costs and benefits of DSM programs?

5. What is the level of spending by both utilities and customers, expressed in common units such as % of revenue, cents/kWh, etc.?

6. What criteria have various areas and entities used to determine the optimum level of spending?

7. Who determines what the optimum level of spending is?

Summit Blue Consulting and the Regulatory Assistance Project joined to determine the current state of energy efficiency and demand response in key states and provinces that could offer insights to CAMPUT. Our goal was to look for common threads, indicators of success. We also gathered data to support choices to engage in energy efficiency, illuminating things to watch out for. We identified jurisdictions with experiences useful for CAMPUT and interviewed knowledgeable people and applied what we learned and already knew from previous and current work. It is clear there is no single best way to implement energy efficiency and demand response, and electric energy efficiency is distinct from natural gas energy efficiency. Yet there are questions that regularly emerge, and sets of internally consistent choices regulators make that lead to a coherent, satisfying program. From this experience, we gleaned some insights for CAMPUT.

Overall spending levels have, in most cases, not been at a level sufficient to realize most of the cost-effective DSM in any jurisdiction. This is due to several factors: 1) concerns about the immediate rate impact of energy efficiency costs; 2) the inherent caution present in most legislative or regulatory proceedings; 3) changes in energy prices, particularly natural gas prices, between the time the enabling legislation or regulations were enacted and the present; and 4) rate structures that penalize utilities for conducting DSM programs. The research revealed seven key approaches to setting DSM funding levels.

1. DSM Spending Based on Cost-Effective DSM Potential Estimates

2. DSM Spending Based on Percentages of Utility Revenues

3. DSM Spending Based on Mills/kWh of Utility Electric Sales

4. DSM Spending Levels Set through Resource Planning Processes

5. DSM Expenditures Set through the Restructuring Process

6. Levels of DSM Tied to Projected Load Growth

7. Case-by-Case Approach

The scan of DSM issues across jurisdictions provides insights into lessons learned concerning natural gas and electric energy efficiency programs. There are a lot of factors associated with a successful DSM effort – that is the reality in the jurisdictions we examined, and illustrates why regulatory orders in energy efficiency dockets tend to be quite lengthy. The following are recommendations for various issues of interest to CAMPUT members.

It is extremely important that these recommendations not be taken out of context. There are a lot of variables that impact these recommendations that cannot easily be summarized. It is critical to read Section 4 of this report to understand the implications and nuances related to these recommendations.

Setting Appropriate Targets for the Amount of DSM

Determining the appropriate level of DSM is a challenging task for any utility, jurisdictional, or regional organization. There is no single or predominant approach but in many cases results are similar in terms of rough size of targeted savings and dollars allocated, sometimes as a percent of total revenues. Overall recommendations based on the scan of jurisdictions implementing DSM for several years are:

- *A minimum expenditure of 1.5% of annual electric revenues might be appropriate with a ramping up to a level near 3%.* These figures are irrespective of whether a jurisdiction has adopted retail electric competition or imposed generation divestiture, though regulatory oversight details may be quite different in either case.

- *Higher percentages may be warranted if there is expected to be rapid growth in electric demand or an increasing gap between demand and supply due to such things as plant retirements or siting limitations.* Even those states with 3% of annual revenues as an expenditure target have found that there have typically been more cost-effective DSM opportunities than could be met by the 3% funding.

- *For gas utilities, the expenditure levels have been found to be lower in virtually every jurisdiction examined.* No good reason was found for this other than that gas has not received as much attention as electricity in analytic studies. Gas space heating and water heating, as well as industrial uses, can benefit from DSM efforts. Given the history observed through the interviews, recommending a range of 1% to 2% for gas DSM is consistent with industry practice.

- *These DSM targets should be reviewed periodically.* California calls for a review every three years, Texas requests annual DSM forecast and filings to ensure the 10% of growth is being obtained by the DSM programs offered, and Idaho and British Columbia conduct an IRP update every two years. It is important to update avoided costs used as the benchmark for determining cost-effective DSM, and to incorporate any unforecasted events (e.g., the recent rise in the price of natural gas) that might change the economics of DSM versus other resources. The review should take into account the importance of maintaining a critical mass of basic capacity within markets for implementing energy efficiency programs, such as contractors, craftsmen, and trade ally relationships.

Cost Recovery of DSM Expenditures

Cost recovery of expenditures is important for organizations spending monies and implementing DSM programs. Most utilities and regulators prefer to expense efficiency costs; in the long run, this is less expensive than capitalizing – deferring and amortizing – them. The only exception is where programs are being started from scratch, and decision-makers are worried about rate impacts. Expensing DSM program costs, possibly through a balancing account, seems to be an acceptable approach but there are probably several acceptable approaches. If near term rate impacts are a concern, capitalizing a portion of the costs may be appropriate. In general, jurisdictions address issues of cost recovery once a DSM target is set.

Of greater interest is how potential disincentives (e.g., lost revenues) are treated. Jurisdictions that allocate an automatic or formulaic budget to energy efficiency create a disconnect between DSM funding and other resource decisions made by utilities and regulators. A regulatory process that compares the values of all resources is more likely to settle on the least cost mix of resources, factoring in the long run and known risks. Updating DSM plans is important either when using a resource planning process or a benefit-cost analysis based on updated avoided costs. Failure to periodically analyze such a budget poses planning risks and decreases the flexibility to address unexpected events through DSM programs. A key component of the value of DSM investments is portfolio diversification and risk mitigation.

Addressing Incentives and Disincentives for DSM

Organizations that traditionally earn profits from selling a product now work with customers to help them use less of their product which lowers overall revenues and potentially lowers profits. This disincentive is real and should be addressed either through an adjustment clause that tracks and makes the utility whole (or mostly whole) for lost margins due to lower revenues, or through a decoupling option to eliminate this disincentive.

The overall recommendations are:

- *Lost margins due to lower sales of electricity and/or gas should be addressed such that it is not a disincentive to utility investment in DSM.*

- *Where additional incentives to meet or exceed DSM targets have been used, the impact on the utility and its rate-payers appears to be positive.*

Benefit-Cost Tests and Avoided Costs

Assessing and evaluating DSM accomplishments are important on a prospective basis to develop a cost-effective mix of DSM programs, and on a retrospective basis to discern whether the expected benefits were actually obtained. These retrospective studies also can be used to develop a more cost-effective mix of DSM activities and provide suggestions on how to make a specific program more effective. The use of benefit-cost tests reflects the importance that regulators in a jurisdiction place on different factors. This is one reason why there are five tests incorporated into the methodology in common use today—the California Standard Practice Manual tests. There is no single answer to the question about which test to use and how to construct it, but this effort provides the following recommendations for use of benefit-cost tests:

- *The primary test that should be used is the Total Resource Cost Test applied to a portfolio of programs, with program specific tests used to address appropriate program design and the mix of programs in the portfolio.* For retrospective analyses, it is important to understand that delivering a DSM program is like introducing a new product into a market. Some programs will likely work better than expected, while others will encounter problems that need to be rectified. As a result, it may be unreasonable to expect all programs to pass the TRC test, but the portfolio as a whole should pass the TRC test.

- *The Participant Test should be part of implementation to ensure that customers that participate in the program do benefit, but it should not have a significant role in setting overall DSM expenditure levels.* Rather, it is useful in the design of specific programs to ensure that the customer perspective in represented.

- *The other tests commonly calculated can be used to provide different perspectives.* If there is a large discrepancy between a ranking of DSM activities based on the TRC Test and one based on the RIM or Societal Test, then the planning process should be flexible enough to make adjustments. Also, if one program drops substantially in its ranking relative to other programs, it may pose some equity problems across customers that could be corrected by making adjustments in the program. It is recommended that the TRC Test generally be the guide, with other tests used to check for extreme differences suggesting some flexibility in the design of a DSM program or the mix of DSM activities.

- *The benefit-cost tests need accurate estimates of avoided costs.* This means that this should include not only avoided costs of generation (i.e., the commodity cost), but also avoided transmission and distribution (T&D) costs. Progress is being made on determining avoided T&D costs in various states that have started to focus on this issue. It is recommended that the best estimates of avoided generation and T&D costs both be used in the application of these tests.

DSM Program Assessment, Monitoring, and Evaluation

Any investment of ratepayer funds should be the subject of ongoing assessment and verification to provide assurances anticipated benefits are being attained, and feedback on the programs and their implementation such that they may be improved over time. There is extensive literature in this area from many jurisdictions. California is adopting evaluation protocols and BC Hydro has developed a state-of-the-industry evaluation approach; other regions have a long history of evaluating energy efficiency programs. The New York State Research and Development Authority has conducted three years of evaluation of their SBC funded Energy $mart^{SM} programs. And many New England states have helped pioneer evaluation literature as their evaluations have had to meet scrutiny required by payment of incentives.

Specific recommendations are:

- *At program design and initiation, key success factors in terms of number of participants, measures installed, monies spent, trade allies signed up or participating, customer satisfaction, and a timeline for meeting these success goals need to be developed.*

- *Also at program design, the data collection to be used to assess energy savings will need to be incorporated into a program tracking system with customer IDs such that sites can be sampled as part of a monitoring and verification process.* These data will also be used to estimate overall program impacts, net of what would have happened without the program. The key is to have an evaluation plan completed at program initiation so all data needed for evaluation will be in program records when it is time for evaluation.

- *An approach used by BC Hydro is representative of current state-of-the-practice evaluation efforts.* This consists of:
    - A complete evaluation plan prepared at DSM program initiation.
    - Actual evaluations conducted at major milestones or at program completion.
    - Process, market, and impact evaluations are conducted, and are overseen by a cross-functional DSM Evaluation Oversight Team.
    - For programs including larger individual projects, technical and financial reviews are conducted before an incentive is offered to provide assurance the technology is feasible, estimated electricity savings are reasonable, and the cost-effectiveness is acceptable.

Interest in DSM, Leadership, Pricing, and Other Factors

There are many facets to launching and overseeing quality energy efficiency and demand response programs. Success does nothing to diminish the appropriate level of oversight and vision needed to be effective. Some essential threads:

- *Leadership is needed to push through the challenges that invariably arise and to keep the longer term in mind – a DSM program may not be immediately cost-effective and it will take time for the value of DSM to be realized.* Good leadership can set appropriate expectations and timelines, as well as ensure that the effort is sustained and is one component of a multi-year plan.

- *A stakeholder process encompassing trade allies, customers, and other stakeholders can be valuable to gain new perspectives and support for programs.*

- *Demand response needs to be integrated with energy efficiency since there are complementary aspects in delivery and economies that can be gained through technologies that both save energy and provide the customer with the ability to manage their energy use such that they can participate in a DR program.*

- *Pricing of electricity and gas is important for the economics of energy efficiency and demand response.* Time differentiated rates that recognize the varying value of the resource across hours and also better reflect the full societal cost of new resources will make DSM look more favorable to planners and customers.

1. INTRODUCTION

Like many government agencies interested in energy policy in 2006, the principals of the Canadian Association of Members of Public Utility Tribunals (CAMPUT) are taking a closer look at energy efficiency. Rising and volatile natural gas prices represent one reason for this increased interest, but these add to long-standing reasons for promoting demand-side management (DSM) – a track record of saving energy at a low cost, the expense and difficulty of adding new generation and transmission capacity, increased attention to climate change in addition to pollution control, energy security, and local economic development. Energy efficiency funded by utility consumer payments has merit because the measures produce benefits to all consumers and to society as a whole, not just benefits to program participants, and because without these programs, most of these investments would not occur.

In the U.S., the National Petroleum Council, an advisory group to the Secretary of Energy made up of oil and gas companies, recommended in 2003 that in response to rising natural gas prices, energy efficiency for the electric and gas sectors is their number one recommendation among others that would enhance energy supplies. Efficiency is cited not just for its effectiveness, but because it is a resource that North Americans can control generally independent of global politics or environmental permitting. Fossil fuel markets have remained volatile and gotten even more expensive since then.

For jurisdictions reassessing or beginning an energy efficiency program, significant experience in the United States and Canada offers the opportunity to apply to new efforts the lessons of success and failure, coincidence and mistake, wisdom and shortsightedness. DSM programs have been underway for nearly 30 years. In each state and province, there are distinct features and also patterns consistent among many jurisdictions. The amount of money committed to energy efficiency is a critical element, but there is a long list of important factors that determine the quality of energy efficiency programs. This report will lay out these factors so regulators can get a picture of the whole task before them. Energy efficiency for natural gas utilities is generally organized similarly to electricity utility programs, but there are important distinctions between gas and electric DSM.

States and provinces have discovered that influencing electric customer behavior can be particularly valuable at peak times. While many jurisdictions have used interruptible contracts for decades, increasingly competitive wholesale markets are introducing demand response programs with a regional scope. These are being enhanced with pilots investigating more “dynamic” pricing, improving the match between the cost to produce electricity and the price to consume it.

In this assignment, Summit Blue Consulting[1] and the Regulatory Assistance Project are joining to find out the current state of energy efficiency and demand response in some key states and provinces, ones that can offer insights to CAMPUT. We are looking for common threads, for indicators of success. We are also accumulating data that will support choices to engage in energy efficiency, while illuminating things to watch out for. We will apply what we learn in our interviews, as well as what we already know from work that we do in the U.S. and Canada. It is clear that there is no single best way to implement energy efficiency and demand response, and that electric energy efficiency is distinct from natural gas energy efficiency. Yet there are questions that regularly emerge, and sets of internally consistent choices that regulators make that lead to a coherent, satisfying program. From these kernels of experience, we will provide insights on how Canadian provinces can cultivate a new commitment to efficiency.

[1] Summit Blue Consulting is located in Boulder, Colorado, and this assignment was performed jointly with its partner company Summit Blue Canada in Ontario.

The balance of this report is organized as follows: Section 2 discusses the objectives of this assignment and the research approach; Section 3 presents a general discussion of the information developed from the research approach; and Section 4 builds on the information from Section 3 to examine important choices facing regulators in relation to DSM.

2. OBJECTIVES OF ASSIGNMENT AND RESEARCH APPROACH

CAMPUT's RFP listed seven items that would provide insights and information to lead to a reasoned approach for addressing the overall engagement objective stated on page 1 of the RFP – "*What is the appropriate level of spending on DSM and what are the best mechanisms to ensure the testing of costs/benefits with a view to adopting guidelines for use by utilities and regulators?*"

The seven specified research items on page 2 of the RFP are:

8. The present level of interest in DSM in Canada and the US and how this may vary between areas in which deregulation has occurred and those areas which are still served by vertically integrated utilities.

9. Is the interest in DSM mainly driven by government, utilities, regulators, or others?

10. For areas that are promoting DSM, what types of programs are being promoted, e.g., load shifting, conservation, interruptible load, etc.?

11. What types of tests are used to determine the costs and benefits of DSM programs?

12. What is the level of spending by both utilities and customers, expressed in common units such as % of revenue, cents/kWh, etc.?

13. What criteria have various areas and entities used to determine the optimum level of spending?

14. Who determines what the optimum level of spending is?

The consultants used two significant approaches to this research. We identified 15 states and provinces we felt would have experiences useful from the point of view of CAMPUT members. These jurisdictions were not randomly chosen. A judgmental process[2] was used where states and provinces were selected which, based on the experience of the authors, have been or are becoming active in DSM. As a result, this indicated a relatively high level of interest in DSM. In addition, we chose several states that bordered on Canada.[3] We interviewed knowledgeable people in these jurisdictions. We spoke with staff from the regulatory agency, the utility, and the energy efficiency administrator where such exists. We crafted these interviews into summaries, and these are provided in Appendix A.

[2] There certainly could be different groupings of jurisdictions that fit the selection criteria, but it was judged that this mix of states would illustrate the DSM issues meant to be addressed by this report.

[3] There was a request in the comments on the draft report that an attempt should be made to rank all states and provinces with respect to their interest in DSM. After internal discussions, it was decided that such a judgmental ranking would not be very useful. For example, one stakeholder may be extremely interested in DSM but another entity may be working to delay DSM activities. Within a state, there are so many stakeholders with different views, that it is hard to make a judgment that others would tend to agree with. Also, there may have been recent changes at the regulatory level that are in the process of causing an increase in interest in a state. There is no central source for these data and, since we didn't interview all States, this would be difficult to ascertain. Determining what is going on across all jurisdictions is a difficult and time consuming task that is beyond the scope of this effort. The approach in which those states/provinces that the authors knew were actively addressing DSM issues would be surveyed was believed to be the best compromise.

Deregulated	***Traditional***
California[4]	British Columbia
Connecticut	Iowa
Illinois	Minnesota
Massachusetts	Vermont
New Jersey	Washington
New York	Wisconsin
Ontario	
Oregon	
Texas	

The interview questions addressed the level of interest in energy efficiency in the jurisdiction, from whom, and how that has changed lately. The consulting team collected information on what types of DSM programs are underway in each jurisdiction, and some important facts about them, as well as governance and responsibilities. Naturally, there are several money issues: how much is allocated and why; how the cost of DSM is compared with other resources, if it is; and how costs are recovered from utility consumers. The results of these interviews are reported in Section 3.

Secondly, we applied our significant experience in energy efficiency and demand response, both from inside government and as consultants to government and industry, to distill this information and augment it with other knowledge. This has become Section 4 of this report. Here we lead the reader through the many decisions that successful jurisdictions have already navigated to achieve high performing energy efficiency and demand response programs.

[4] Partially restructured.

3. Research Findings

This section presents the research findings on the seven questions posed by CAMPUT, discussed in Section 1. These findings are primarily based on the interviews conducted on 15 jurisdictions covering 13 U.S. States and two Canadian provinces, but also incorporate previous research conducted by members of the project team.

3.1 Approaches to Setting DSM Spending Levels

This section presents the research findings regarding current levels of utility or "public benefits" DSM spending, how jurisdictions optimize DSM spending, and the ultimate decision maker regarding the optimal level of DSM spending in each jurisdiction.

3.1.1 Discussion of Approaches

Every jurisdiction faces a combination of political, economic, and societal goals that plays some role in determining the level of DSM spending. As a result, setting spending levels on DSM may include a number of different elements, e.g., a resource planning approach as well as a set of societal objectives. The diverse approaches for setting spending levels may make it seem like these approaches are more arbitrary than is actually the case. In the debates that lead to most DSM spending recommendations, there are several recurring themes: 1) the costs of building supply-side options (generation and delivery) that may be avoided due to DSM programs; 2) the size of the specific target markets for DSM programs; and 3) a discussion of the magnitude and types of DSM programs that make the most sense for that jurisdiction given energy prices and past investments in DSM.

Discussions before a province/state regulatory body or state legislature typically involve a variety of stakeholders with diverse opinions relying on different methods to support their cases. The final decision may involve a compromise between various positions and supporting methods. The California Public Utilities decision setting DSM targets, discussed in the first approach (below), illustrates this expansive approach. DSM targets and funding in California illustrate the types of positions[5] and compromises that are common in the target setting process. In some jurisdictions, these discussions were held a number of years ago but, with interest in DSM increasing in almost all jurisdictions with higher energy costs, many of these issues are currently being revisited.

For the purposes of this discussion, seven approaches to setting DSM spending levels are identified, with each discussed below. Several jurisdictions use more than one approach to setting DSM spending levels, often based on compromises stemming from the decision making process, so the categorization below is approximate, and is based on the primary factors used in each jurisdiction.

Approaches to Setting DSM Spending Levels

1. Based on Cost-Effective DSM Potential Estimates
2. Based on Percentages of Utility Revenues
3. Based on Mills/kWh of Utility Electric Sales
4. Levels Set Through Resource Planning Process
5. Expenditures Set Through the Restructuring Process
6. Tied to Projected Load Growth
7. Case-by-Case Approach

[5] See INTERIM OPINION: ENERGY SAVINGS GOALS FOR PROGRAM YEAR 2006 AND BEYOND; California Public Utilities Commission Decision 04-09-060 September 23, 2004.

APPROACH 1: DSM Spending Based on Cost-Effective DSM Potential Estimates

California bases DSM spending levels on the amount of cost-effective potential DSM in their jurisdiction. The California Public Utility Commission (CPUC) requires the four major Investor-Owned Utilities (IOUs) to procure all cost-effective DSM before pursuing supply-side options. The IOUs must meet annual MWh/therm savings goals, which are based on capturing 90% of all feasible efficiency. Funding is based on the cost of meeting the targets and requirements obtained from studies assessing the cost-effective potential of DSM in different target markets. Budgets are established for meeting these targets with the funds coming from a public goods charge, procurement budgets, and rates. An important element of the CPUC decision on spending levels was that the energy savings goals should be updated on a regular basis. The CPUC stated in Decision D0409060 that it is "our objective to capture all cost-effective energy efficiency that we establish numerical targets for electricity and natural gas savings today, and create a process for updating them on a regular basis in the future."

It is also important to note that the CPUC DSM targets are not a simple one-time target, but reflect a trajectory of increasing DSM over a period of 10 years, with updates scheduled every three years. This reflects the design, implementation, and penetration cycles that exist in DSM programs.

APPROACH 2: DSM Spending Based on Percentages of Utility Revenues

Four states, Minnesota, Oregon, Vermont, and Wisconsin have specified DSM spending levels as percentages of utilities' revenues. This percentage was generally arrived at through political processes at state legislatures.

- Minnesota – The State Legislature has determined statutory minimums that utilities must spend on DSM. [6] This is currently set at 0.5% for gas utilities and 1.5% to 2.0% for electric utilities, depending on whether or not a utility owns nuclear power plants. The Minnesota Public Utilities Commission can require electric utilities to exceed their statutory minimum DSM spending requirements through integrated resource plan (IRP) proceedings.
- Oregon – The two largest electric IOUs must spend 3% of their revenues on DSM and renewable energy efforts[7], and the largest gas utility must spend 1.5% of its revenues on DSM. Oregon's electric DSM spending requirements are set by statute, and are essentially fixed without legislative revisions to the governing statute, although current regulatory proceedings on least cost planning may provide some flexibility for DSM funding in the future. The gas utility's spending was determined in a regulatory proceeding.
- Vermont – The utilities are required by statute to capture all cost-effective efficiency, an obligation that is met through a statewide energy efficiency utility (EEU). In practice, however, DSM programs have historically been funded by a 3% surcharge on utility bills, which effectively caps DSM spending and may prevent all cost-effective potential from being captured. In 2005, the Legislature lifted the cap, and it is expected that the EEU's budget will increase, allowing it to capture a greater percentage of potential efficiency. How this will play out is currently uncertain. [8]
- Wisconsin – This state uses a 3% surcharge on IOU customers' electric bills as the largest funding component for its "public benefits" DSM programs, which transitioned from utility managed DSM programs starting in 2000. Wisconsin also uses other funding mechanisms for its DSM programs, including continuing pre-2000 gas DSM program funding, separately funded

[6] Minnesota statute 21B.241 covers the Conservation Improvement Program requirements.

[7] Over 80% of Oregon's electric public purpose charge is used for efficiency efforts; 17.1% for renewable energy.

[8] VSA 30, section 209c.

utility-managed load management and demand response programs, requiring utilities to conduct their own DSM programs as a condition for receiving approval to build new generating plants, and federal low-income weatherization funds.[9] Wisconsin's legislature has diverted about 40% of the funds intended for its Focus on Energy public benefits DSM programs to help balance the state's budgets in the last several years.

APPROACH 3: DSM Spending Based on Mills/kWh of Utility Electric Sales

Two states, Connecticut and Massachusetts, have specified electric DSM spending levels of 3.0 and 2.5 mills/kWh of utilities' total electric sales, respectively. These funding levels were specified by statutes as these states restructured the electric utility industry in the late 1990s, and can only be changed through legislative action. A securitization mechanism adopted by Connecticut's legislature to help balance the state budget will divert approximately 1 mill/kWh of DSM funds for about seven years.

APPROACH 4: DSM Spending Levels Set through Resource Planning Processes

Several jurisdictions contacted were found to require or allow utilities to implement the DSM programs that are found to be most cost-effective over time through an IRP process, or similar proceedings that involve viewing DSM as a resource on par with supply-side resources. Jurisdictions contacted that use this approach as their primary methods for setting DSM spending requirements are British Columbia, Idaho, Iowa, and Washington. Vermont is considering adopting such a process to overlay the current approach (see Approach 2).

These jurisdictions do not use any type of formulaic DSM spending guidelines or requirements. As an example, in Idaho, the largest electric utility (Idaho Power Company) has to file a formal resource plan before the State Commission every two years. This plan must include both DSM and renewables. The overall plan selected is the one that is deemed to be most cost-effective for meeting future electric needs taking into account supply-side, DSM, and renewable resources. A formal modeling approach and a structured stakeholder process are used in Idaho. By performing this planning exercise every two years, risks of changes in the market conditions are mitigated since the plan is revised on a regular basis.

Iowa does not use a formal IRP process, but compares costs of DSM to avoidable costs of new supply to determine the amount of DSM that is cost-effective. Other jurisdictions where a resource planning approach is used include:

1) The smaller gas and electric utilities in Oregon also invest in DSM as a result of IRP proceedings.

2) Gas utilities in Connecticut implement DSM programs approved in the context of supply/demand regulatory proceedings.

3) Gas utilities in Massachusetts present five-year DSM plans proposed by gas utilities in regulatory proceedings.

APPROACH 5: DSM Expenditures Set Through the Restructuring Process

A number of jurisdictions that have gone through restructuring and an unbundling of energy services have set spending amounts for DSM using a variety of governmental processes. Three such jurisdictions that have restructured their electricity markets are New Jersey, New York, and Ontario. In general, these

[9] Wisconsin's "Reliability 2000" legislation was contained in 1999's Wisconsin Act 9 (the 1999-2000 Biennial Budget Act).

levels were set as one component of the political process that resulted in the restructuring orders or legislation.

- New York – Annual electric DSM spending for SBC programs was set by the Public Service Commission as part of the re-authorization of the state's energy "public benefits" programs, [10] and recently extended for 2006 through 2011 at $175 million per year. [11]

- New Jersey – The Board of Public Utilities (BPU) recently assumed responsibility for managing the states' DSM programs from the utilities. New Jersey DSM funding is set at $140 million in 2005, and is projected to increase to $235 million in 2008. Funds for DSM programs in New Jersey and New York are raised by a "systems benefits charge" on IOU utility bills.

- Ontario – The Ontario Energy Board has approved $163 million of total funding for electric distribution company DSM programs for 2005 to 2007, and $25 million for gas DSM programs for 2005 to be recovered in utility rates.

APPROACH 6: Levels of DSM Tied to Projected Load Growth

Several states, Texas, Connecticut, and Illinois, require their electric investor-owned utilities to meet set percentages of their load growth through DSM. These states have restructured their electricity markets.

- Texas – The electric IOUs must meet 10% of their projected load growth through DSM.

- Connecticut – Recently enacted legislation in Connecticut is a variation on this approach, requiring an increasing percent of the state's electric supply to be met with distributed resources, reaching 4% by 2010. Certain DSM savings will count towards this distributed resource portfolio standard.

- Illinois – The Illinois Commerce Commission (ICC) has initiated a proceeding to implement the Governor's proposed Sustainable Energy Plan. [12] The Governor's proposal would require each of the state's electric IOUs to meet 10% of their load growth through DSM starting in 2006 or 2007, increasing over time to a maximum of 25% in 2015.

APPROACH 7: Case-by-Case Approach

Many jurisdictions do not actively regulate DSM spending or do so on an ad hoc basis, such as through rate case settlements. Jurisdictions have varying reasons for not directly trying to develop spending levels tied to some approach to achieving cost-effective DSM spending. Some jurisdictions have experienced utility and/or large industrial customer opposition to DSM.

---

[10] Large customers were able to opt out of this public benefits charge arguing that they already have incentives to pursue all cost-effective energy efficiency. Large customer opposition to DSM spending, where some spending shows up in their rates, has been common. As a note, large customers are leading the way in energy efficiency expenditures in Idaho using an innovative approach creating a pool of money that any large customer can draw from for a cost-effective energy efficiency project. Since money is paid into the pool by the utilities, it is a use-it or lose-it proposition for these customers; Idaho has seen them aggressively compete for these energy efficiency dollars.

[11] Order Continuing the System Benefits Charge (SBC) and The SBC-Funded Public Benefit Programs (issued December 21, 2005).
http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/5375707FAF2225B2852570D600700767/$File/05m0090_12_21_05.pdf?OpenElement

[12] See ICC web site: www.icc.illinois.gov, "Sustainable Energy Plan".

The information presented previously is summarized in Table 3-1 below.

Table 3-1. Summary of DSM Targets and Spending Amounts

State/Province	DSM Targets and Authorized Amount (Electric)	DSM Targets and Authorized Amount (Natural Gas)
British Columbia	All DSM that is cheaper than supply (This as resulted in expenditures that are about 3.3% of electric revenues)	Utility determined
California	Authorized budgets are based on funding levels necessary for utilities to meet CPUC savings targets by procuring cost-effective efficiency.	
Connecticut	3 mills/kWh (due to diversion by legislature, only 2/3 available for several years)	Varies within context of statutorily required supply and demand plans. Expected to increase due to new law.
Idaho	Approved as part of the Integrated Resource Plan (currently there is a 1.5% adder on to rates to pay for DSM approved by the State Commission. DSM is a relatively new initiative for Idaho)	
Illinois	Utilities must meet set percentage points of load growth through DSM	NA
Iowa	The regulator approves prudent, cost-effective efficiency in utilities' 5-year plans	
Massachusetts	2.5 mills/kWh	Varies with results of individual gas utility DSM plan regulatory proceedings.
Minnesota	Minimum spending: 2% of electric revenues for Xcel Energy; 1.5% for non-nuclear utilities. Integrated Resource Plan may result in increase.	Minimum spending: 0.5% of gas revenues
New Jersey	Balance cost-effective DSM with impact on rates; $1/MWh for economic DR	
New York	$175 million/year for SBC funded energy efficiency.	
Ontario	$163 million for 2005-2007	$25 million for 2005
Oregon	Public purpose charge of 3% of revenues of two major electric utilities; 57% administered by ETO for efficiency; 17% for renewables; remainder administered by others for low-income and school efficiency. Other utilities vary with Least Cost Plan.	1.5% of revenues of major gas utility; with 1.25% administered by ETO; 0.25% administered by utility for Low Income; other utilities vary with Least Cost Plan but less than 0.5% of revenues. Expected to increase.
Texas	Utilities must meet 10% of forecasted growth in demand through efficiency or approved load management.	NA
Vermont	Historically wires charge was capped at about 3% of electric revenues; in 2005 legislature removed cap.	Spending for one gas utility set in Integrated Resource Plan proceedings.
Washington	Based on Least Cost Plan	
Wisconsin	Up to 3% of electric revenues	Based on spending by utilities before the public benefits charge (1999).

The summary of approaches presented above is focused on electric energy efficiency spending. Jurisdictions vary considerably in how they treat natural gas energy efficiency spending and how they treat spending on load management or demand response programs.

Gas DSM Spending

It is almost universally the case that gas energy efficiency spending requirements are considerably less demanding than the corresponding electric DSM spending requirements. This situation is due to several factors: historically gas was a less expensive energy source than electricity, gas competes with unregulated heating oil in some locales, and new gas supply facilities generally raise less public opposition than corresponding electric plants and transmission lines. However, many jurisdictions have rebate programs targeted at major natural gas end-uses (i.e., space heating and water heating).

Several examples comparing gas to electric DSM spending requirements are shown below:

- In Illinois and Texas, gas IOUs are not covered by DSM spending requirements; electric IOUs are.

- In Minnesota, gas utilities must spend at least 0.5% of their revenues on DSM, compared to electric utilities that must spend 1.5% to 2.0 % of their revenues on DSM. The situation is similar in Oregon, where the largest gas utility must spend 1.5% of their revenues on DSM, compared to the largest electric utilities that must spend close to 3.0% of their revenues on DSM.

- In Vermont, total annual electric DSM spending is approximately $15 million, compared to Vermont Gas System's approximate $1 million annual budget for gas DSM.

Load Management and Demand Response Spending

Most of the focus on spending levels for DSM has been on energy efficiency. However, interest in load management and demand response has been increasing in recent years both because of rising end-use prices and because restructuring has exposed more end-use customers to the volatility of electricity prices in wholesale markets. Approaches to load management and demand response also vary considerably across jurisdictions.

Five types of approaches to load management and demand response were found in this review:

1. British Columbia, Illinois, Iowa, Minnesota, New York and Ontario treat load management or demand response similarly to how they treat electric energy efficiency programs. Load management or demand response program spending and/or impacts count towards overall DSM requirements.

2. California and Wisconsin encourage utilities to conduct load management and demand response programs, but regulate these programs in separate proceedings from energy efficiency programs. California takes this a step further by dividing demand response into two categories:

    A. <u>Price Responsive Load</u> – These are demand response programs that use price triggers and includes pricing programs such as Critical Peak Pricing (CPP) and Day-Ahead Pricing (DAP). These programs are event-based, i.e., the California utilities have to call for a CPP or DAP event;

then, customers are exposed to a high prices on those days and they have the choice as to whether they want to respond or simply absorb the high price.[13]

B. Curtailable Load Programs – These are the conventional load management programs where the utility has interruptible customers and can call on them for a load reduction. This includes such programs as simple large customer capacity call programs and direct load programs common to mass markets (e.g., direct load control of air conditioning or water heating).

California has been focusing on both sets of programs but with a recent emphasis on pricing to achieve load reductions. A 2003 California Public Utilities Decision[14] directed the utilities to achieve the capability to reduce their peak demand by 5 percent using price-responsive load programs in five years. The Commission continues to study the cost-effectiveness of this requirement with a recent set of filings by the utilities (August 2005) and, despite some utility pushback, a 5 percent reduction from price-responsive load programs is still the goal in California.

3. There has been an increased emphasis on demand response in Texas and Connecticut lately, resulting in more funds that were previously focused on efficiency being available for certain demand response or reduction strategies.

4. Massachusetts, New Jersey, Oregon, Vermont, and Washington either have very limited or no local load management or demand response programs available to customers. Utility spending on load management and demand response programs does not count towards DSM spending requirements. Rather, these costs are part of the overall resource procurement for utilities. There is some expectation that this area will become more robust in the near future in several of these states.

5. The Federal Energy Regulatory Commission, which governs interstate electric transactions, has been aggressive in working with the transmission and reliability organizations that perform dispatch and monitor the transmission grid to offer demand response programs. Generally, these organizations have been the Independent System Operators (ISOs).[15] The ISOs that offer reasonably aggressive demand response programs include the ISO New England, the New York ISO, the PJM ISO, and the ERCOT ISO in Texas. The states in these regions vary with respect to how they interact with the ISO programs. As a few examples:

   – New York ISO – The New York State Research and Development Authority (NYSERDA) directly uses monies collected from the Societal Benefits Charge levied by all the utilities to fund energy efficiency programs, but it also has programs that are designed to encourage customer participation in the New York ISO programs through both information and enabling technologies.

   – New England ISO States –ISO-New England encourages electric distribution companies to aggregate customers and participate in their programs by allowing the distribution company to retain a portion of the payments to customers that participate in the demand response programs.

[13] These price-responsive load programs expose customers to price volatility in return for lower prices on non-event days in off-peak periods.

[14] The most recent CPUC ruling re-affirming these demand response targets is in: California Public Utilities Commission, OPINION APPROVING 2005 DEMAND ESPONSE GOALS, PROGRAMS AND BUDGETS, Rulemaking 02-06-001, Decision 05-01-056 January 27, 2005.

[15] For the purpose of this report, the distinction between ISO and RTO, Regional Transmission Organization, is not material. We will use the term ISO for simplicity.

– PJM ISO States – Pennsylvania, New Jersey, and Maryland have had a long tradition of demand response programs, primarily through rules that allow load providers to count demand response toward meeting their operating reserve requirements. With restructuring and creation of PJM as an ISO and the creation of active wholesale markets, PJM has developed its own reliability and economic demand response programs. Many of the individual state-level programs predate the development of demand response programs at PJM. The PJM ISO programs have been developed to co-exist with and augment the existing state and utility programs. The long term commitment to energy efficiency and DR among the original PJM states (i.e., the Mid-Atlantic States) has resulted in some large demand response programs (e.g., Baltimore Gas & Electric has over 300,000 customers in its demand response programs).

3.1.2 Summary of Research on DSM Spending Levels

The recent American experience with simple DSM spending requirements (e.g., mills/kWh, percent of revenue, or a specific dollar figure) reveals that spending levels have, in most cases, not been at a level sufficient to realize most of the cost-effective DSM in any jurisdiction. This is due to several factors:

- *The inherent caution present in most legislative or regulatory proceedings.* Few legislators or regulators want to become known as someone who authored requirements that could not practically be achieved.

- *Changes in energy prices, particularly natural gas prices, between the time the enabling legislation or regulations were enacted and the present.* For example, Minnesota's DSM spending statutes were last significantly updated in 1994. At that time the wholesale price of natural gas was approximately $2 per million BTUs, compared to the current natural gas wholesales prices of over $10 per million BTUs. More DSM will be cost-effective at today's high natural gas prices than was cost-effective when natural gas costs were much lower. This is true for both electric and gas DSM, as marginal new electric generating units are often fueled with natural gas.

- *Rate structures that penalize utilities for conducting DSM programs.* Decreasing sales through DSM programs also can reduce utility profits unless rate mechanisms that "decouple" utility profits from revenues are in place. Such decoupling mechanisms include allowing utilities to recover the lost profits from the revenues reduced through DSM programs, or tying utility profits to a secondary indicator such as the number of customers served instead of revenues.

- *Concerns about the immediate rate impact of energy efficiency costs.* This is a concern even when there is appreciation for long term cost savings to the utility system. As supply alternatives get more expensive, their rate impacts will become more onerous in comparison with efficiency. In addition, it is possible to ramp up DSM programs and expenditures over a two to three year period which can serve to mitigate price impacts even if these programs are funded by a rider on existing electric tariffs.

A process such as an IRP proceeding or DSM potential study is needed to set DSM targets, and additional procedures are needed to determine the most cost-effective portfolio of DSM programs to attain that target.[16] This will allow for the development of DSM plans that propose levels of program development

---

[16] The CPUC used overall DSM potential as the basis for setting reasonable targets and left the determination of the most cost-effective portfolio for attaining these targets to another proceeding. "The forum and process for considering what program offerings are cost-effective and reasonable will be dictated in large part by the administrative structure we adopt in a separate

and expenditures such that most cost-effective DSM will be implemented over a period of time. This is the case whether the simple DSM spending requirements are expressed in terms of spending a certain percentage of revenues on DSM, or a certain number of mills per kWh on DSM. The common element of processes that seek to optimize DSM spending is that DSM expenditure levels are part of an analysis designed to estimate the potential for cost-effective DSM, combined with a view that DSM is an alternative to developing supply-side resources. Potential studies are based on an increasing body of experience over time and jurisdictions. Generally, spending is not allowed up to levels that would fully test the estimated energy efficiency potential from these studies. On the other hand, one can learn a lot about a market without being overly precise in determining technical potential –regulators just need to know there is enough potential to at least justify the efficiency program and spending plan, which often can be done without an overly detailed study. However, there are other benefits that a DSM potential study can provide. Information from a DSM potential study is often used as the first step in the design of programs since potential studies can document current practices and establish energy use baselines. This information can be used to design the appropriate program for a region and help establish initial customer/trade ally incentives, if incentives are to be used. In addition, if the program is a market transformation one, a baseline is needed to develop market indicators to be tracked over time, providing information on how the market is changing and how much of this change can be attributed to the program. From this perspective, market potential studies can have three goals:

1. To provide an initial estimate of the potential savings that can be achieved from DSM programs to determine overall levels of expenditures on DSM.
2. To provide a baseline set of energy use practices that can help in the design of cost-effective programs.
3. To serve as the first step in the evaluation of programs since all estimates of program impacts and market transformation must be made in reference to a baseline.

Given these possible benefits of DSM potential studies, many jurisdictions spend more money on a potential study than is merely needed to justify a threshold level of expenditures on energy efficiency programs. They also use the results of the study proactively in program design and as the first step in program evaluation. This has caused the “price tag” of some DSM potential studies to be higher than others, depending on the depth of market analysis contained in the study.

The preceding discussion on the use of IRP processes and DSM potential studies is not intended to imply that simple DSM spending requirements are without merit. The clarity and simplicity of such requirements are naturally attractive to policy makers, utilities, and other stakeholders. Such funding requirements can ensure continuity and stability in DSM funding, and help ensure that such funding will not decline dramatically with short-term decreases in energy prices.

Benchmarks are available from other jurisdictions (See Section.4, Issue 1) and ramping up DSM expenditures over time (often a relatively short period of time, i.e., two years) allows programs that are almost certainly cost-effective to be implemented, and it also allows for information to be collected on end-use customer baseline practices as part of program implementation. This provides insight into the DSM potential of programs simply through implementation and good data tracking; a more focused potential study can be implemented after an initial set of DSM activities have been undertaken.

phase of this proceeding.” See: “Energy Savings Goals For Program Year 2006 And Beyond;” California Public Utilities Commission Decision 04-09-060 September 23, 2004.

3.2 DSM Benefit-Cost Analysis

There is an extremely large set of options for DSM programs. Depending upon the talent, creativity, and process with which a DSM program is designed and implemented, DSM programs which on paper appear similar can have quite different benefits and costs when actually implemented. In addition, some programs will simply be more cost-effective than others. As a result, regulators have generally mandated some form of benefit-cost analyses of DSM programs to both ensure that the utilities are being efficient in their implementation of programs, and establish that a cost-effective mix of programs are being offered.

In response to these concerns, utilities conduct DSM benefit-cost analyses that fall into two categories:

1. Dynamic analyses that identify the amount of DSM that is most cost-effective relative to other resources, primarily new energy supplies. This is most commonly done through IRP proceedings.

2. Static analyses that evaluate DSM's cost-effectiveness relative to a fixed set of avoidable supply-side resources and avoided costs.

Of the 15 jurisdictions researched for this project, seven used IRP[17] processes to assess DSM, even if the spending level was not directly tied to the outcome of that process. For example, with a fixed spending target, a resource planning process can identify which DSM programs are the most cost-effective within that spending target. Eight jurisdictions were not judged to use formal IRP processes in DSM assessment. The seven jurisdictions that had IRP elements in DSM planning were British Columbia, California, Minnesota, Ontario, Oregon, Vermont, and Washington. [18] Interestingly, almost half of these jurisdictions (California, Ontario, and Oregon) have either partially or fully restructured their electric utilities. For the eight jurisdictions that do not use IRP processes, all but two (Iowa and Wisconsin) are restructured.

Utilities or power planning organizations use IRP processes to select the lowest cost energy system expansion plan from among many possible options. As part of this process, the planning organization develops at least several scenarios for each type of supply or demand reduction resource. IRP planning periods are generally at least 20 years long (some as short as 10 years with others being as long as 30 years). DSM scenarios can be developed by adding or subtracting different types of DSM programs or technologies between scenarios, adding or subtracting customer groups covered by DSM programs, or varying DSM incentives such as customer rebates between scenarios. There are many models that can be used in an IRP context.[19] Typically, they calculate the long-term costs of various combinations of supply and demand reduction scenarios over the forecast period. Monte Carlo analyses can be used as part of the

[17] The use of the term Integrated Resource Planning (IRP) is meant to generally apply to an analytic process that is comprehensive in its analysis of resources, i.e., both supply-side and DSM (and often renewables) are all analyzed with reasonable characterizations of each resource option to assess the tradeoffs between resources and develop a going-forward action plan for meeting load growth. In some regions, the term IRP has become associated with a narrowly defined process that involved specific modeling activities that were viewed as counter-productive by some utilities and planning organizations. It is hoped that this more general view of IRP will avoid the debate that arises in some regions about the use of an IRP approach.

[18] About half of these jurisdictions (California, Minnesota, Oregon, Vermont) use another type of DSM spending requirement as the primary DSM regulatory approach. IRP proceedings are use to fine-tune DSM spending requirements that are (most commonly) defined by statutory requirements for utilities to spend certain minimum percentages of their revenues on DSM.

[19] Many models are used as tools in performing IRP-type studies. Some of the more models used in the jurisdictions surveyed include ProSym or RiskSym offered by Henwood Associates, PROMOD IV and Strategist offered by New Energy Associates, and the Aurora Model offered by EPIS, Inc. However, there are easily a dozen other models in use by utilities and regional planners and those mentioned. The models cited above are some of the models being used in states that were contacted in this research.

IRP analysis, and are particularly useful to quantify the risks of low probability but high consequence events between scenarios.

IRP analyses can be useful to determine the amount or type of DSM that is most cost-effective over the long term. However, IRP analyses are generally not conducted by utilities that have divested their generation assets, as they are no longer "integrated" utilities. This has resulted in a gap in information analyses as full retail competition has not emerged in most markets. Now, some regulators even in restructured markets are beginning to see the advantages of some integrated planning as are other entities such as state energy offices (e.g., the California Energy Commission) and regional groups (e.g., the Northwest Power and Conservation Council). IRP analyses can require a substantial amount of work for the responsible utilities or planning organizations, and the results can be contentious. As a result, some utilities and regional organizations try to manage the number of such analyses. However, other jurisdictions have found these IRP processes to be very successful and have used IRP processes for over a decade. The standard tools and techniques used in IRPs are generally well understood, although they are evolving over time.

It is hard to characterize the attributes of a successful versus an unsuccessful IRP process for assessing the level and types of DSM that should be targeted. Where it has been judged as being unsuccessful, it was generally seen as too burdensome, with some stakeholders essentially requesting every possible demand-side option be analyzed. Where it has been judged successful, there generally have been good stakeholder processes and accepted screening criteria to reduce the number of DSM options to categories and portfolios that receive detailed consideration down to a manageable level.

In the U.S., the most common types of static DSM program benefit-cost test analyses are done using the California Standard Practice Manual (SPM) approach.[20] These benefit-cost tests are a form of integrated planning, but they generally do not have the dynamic element common to the IRP approach discussed above. The link between the DSM program and supply-side options is made through the use of an "avoided supply cost." This is an estimate, often taken from the results of resource planning model, of the supply-side resource that is on the margin, i.e., is the next option to be built. An adequate amount of DSM could avoid the costs of this marginal unit. As a result, one of the key benefits as defined in these benefit-cost tests is the avoided costs of a supply-side resource. This makes the frequency of updates to the avoided cost number important for good DSM planning.

In general, the California SPM benefit-cost approach uses five "stakeholder" tests to assess the benefits and costs of DSM programs from different perspectives:

- Participant (customer) test. DSM benefits to participants are reduced energy costs from the DSM measures they installed, plus any productivity benefits they may receive from the DSM measures. DSM costs to participants are the net (after rebate) incremental costs of the DSM measures.

- The utility test. The primary benefits of DSM to utilities are the avoided costs they realize from not having to build new energy supply facilities. The DSM costs to utilities are the total costs of the DSM programs.

- The rate impact test (formerly called the non-participant customer test). The benefits for this test are the avoided costs from not having to build new energy supply facilities. The costs for this test are the total program costs plus the "lost revenues" from the DSM measures. This test is similar

[20] California Energy Commission, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects" (California Energy Commission, Sacramento, CA, October 2001).

to the Pareto efficiency test in economics: a policy or project that makes everyone better off without making anyone worse off.

- The total resource cost (TRC) test, essentially the perspective of all utility customers combined. The benefits for this test are the avoided costs from not having to install new energy supply facilities. The costs for this test are the DSM program administrative costs plus the net (after rebate) incremental costs of the DSM measures. This test is similar to the Kaldor-Hicks compensation test in economics: the winners from a policy or project could compensate the losers enough so that they would at least break even.

- The societal test. The societal test is very similar to the TRC test, except that it includes avoided environmental damages due to DSM programs.

The analyses are to be done using the net present value of DSM program benefits and costs over the lifetime of the DSM measures covered by the DSM programs. The DSM benefits should be based on "net" program impacts, that is, program impacts adjusted for free-ridership and spillover.[21]

Table 3-2 is a summary of results for each of these five tests for Xcel Energy's Minnesota Commercial and Industrial Lighting Efficiency Program for 2005. These results are common for many energy efficiency programs: benefit-cost ratios are somewhat greater than one for the participant test (otherwise why would the customer participate?), the TRC test, and the societal test, and much greater than one for the utility test. This program is cost-effective from all these perspectives. It is interesting to note that the environmental externality benefits only account for seven percent of the total societal program benefits, so the societal test results are very similar to the TRC test results. The benefit-cost ratio for the rate impact test is slightly less than one. This means that this DSM program will cause long-term electric rates to be slightly higher than they would be without the program.

[21] DSM program free riders are those program participants who would have installed the DSM measures even without the DSM program. DSM program spillover effects include savings from program participants and non-participants who installed DSM measures due to a DSM program, perhaps due to the program's informational effects, but did not receive any funding from the DSM program.

Table 3-2. Commercial and Industrial Segment Lighting Efficiency 2005 Cost Benefit Summary

	Participant Test $/kW	Utility Test $/kW	Rate Impact Test $/kW	Total Resource Test $/kW	Societal Test $/kW
Avoided Revenue Requirements					
Generation	N/A	$721	$721	$721	$721
T & D	N/A	440	440	440	440
Marginal Energy	N/A	1,604	1,604	1,604	1,604
Externality Willingness	N/A	N/A	N/A	N/A	220
Subtotal	N/A	$2,765	$2,765	$2,765	$2,985
Xcel Energy's Project Costs	N/A	$329	$329	$329	$329
Subtotal	N/A	$329	$329	$329	$329
Revenue Reduction	$2,589	N/A	$2,589	$0	$0
Subtotal	$2,589	N/A	$2,589	$0	$0
Participants' Net Costs					
Incremental Capital	$1,264	N/A	N/A	$1,264	$1,264
Incremental O&M	527	N/A	N/A	527	527
Rebates	(268)	N/A	N/A	(268)	(268)
Subtotal	$1,523	N/A	N/A	$1,523	$1,523
Net Present Benefit (Cost)	$1,066	$2,435	($154)	$913	$1,133
Net Benefit (Cost) per kWh Lifetime	$0.013	$0.029	($0.002)	$0.011	$0.013
Net Present Benefit (Cost) per Generator	$1,212	$2,768	($175)	$1,037	$1,288
Cost Benefit Ratio	1.70	8.39	0.95	1.49	1.61

For the 15 jurisdictions investigated for this project, the most important benefit-cost analysis tests are TRC and societal tests. Six jurisdictions each use these two tests as their primary DSM benefit-cost analysis test. Since these two tests often produce similar results, the jurisdictions researched for this project are quite similar in their conclusions regarding the most important DSM benefit-cost analysis test.

Three jurisdictions primarily use the utility cost test as their primary benefit-cost analysis test. Only one jurisdiction (British Columbia) uses the rate impact test as one of its primary benefit-cost analysis tests. The totals discussed above include some double counting, as a few jurisdictions use one test as the primary test for one type of DSM program, and use a second test as the primary test for other types of DSM programs. One jurisdiction (Illinois) was uncertain about which test would be their primary benefit-cost analysis test. Jurisdictions also vary considerably in how many of the California stakeholder tests they use as part of their DSM benefit-cost analysis. Only Iowa and Minnesota use all five California tests. Five jurisdictions (Massachusetts, New York, Ontario, Texas, and Vermont) only use one test, and three of those jurisdictions use the TRC test. Wisconsin uses the societal test, and developed a new DSM test that models the economic impacts of DSM on the Wisconsin economy.

3.3 Cost Recovery and Incentives

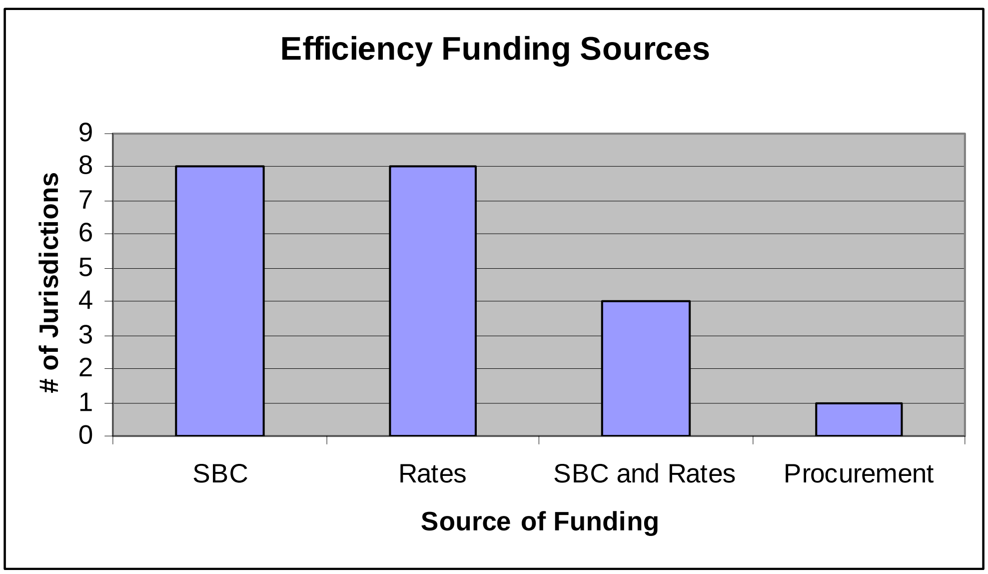
Among the jurisdictions interviewed, a number of different approaches to DSM funding are used. In most areas, load management and demand response programs are recovered directly through rates. Efficiency programs are generally funded by customers either through general rate recovery or through a system benefits charge (SBC). Some areas take a hybrid approach to efficiency funding, using both SBCs and rate recovery, and one state, California, funds efficiency through both an SBC and through utility procurement budgets. ***Regardless of the specific approach taken, DSM efforts are ultimately funded by ratepayers in each jurisdiction.***

When efficiency is funded through rates, the charges are determined by regulators during rate cases and may appear as a per-unit surcharge on wires or supply. This approach may be used by restructured jurisdictions (Illinois, Ontario, and Texas) as well as vertically integrated jurisdictions (British Columbia, Iowa, Minnesota, and Washington).

SBCs are known by a variety of names (a public goods charge in California; a public purpose charge in Oregon). In most cases, SBCs were instituted by statute during a state's restructuring process, with legislatively established funding levels. Some SBCs may have certain restrictions placed on them. In Oregon, for example, specific percentages of SBC funding must be spent on categories like schools and low-income customers, and in California, the SBC also funds renewable energy programs. The establishment of a SBC generally reflects legislative intent to preserve continuity of efficiency programs, which might otherwise have been dropped under the new regulatory scheme. One exception is Vermont, where the SBC was developed during restructuring discussions. In that case, the state chose to adopt the SBC funding mechanism while remaining vertically integrated.

A number of jurisdictions use dual approaches to efficiency funding. In California, meeting the state's efficiency goals requires funding over and above the SBC, and the regulator has authorized funding of efficiency through utilities' procurement budgets. Wisconsin maintains an SBC, and recovers some expenses through rates as well. Connecticut and Massachusetts have an SBC that funds electric efficiency, while gas costs recovery occurs in rates. Oregon and Vermont use SBC funds for programs through statewide efficiency implementers (Energy Trust of Oregon and Efficiency Vermont), and use rate recovery for DSM implemented by utilities.

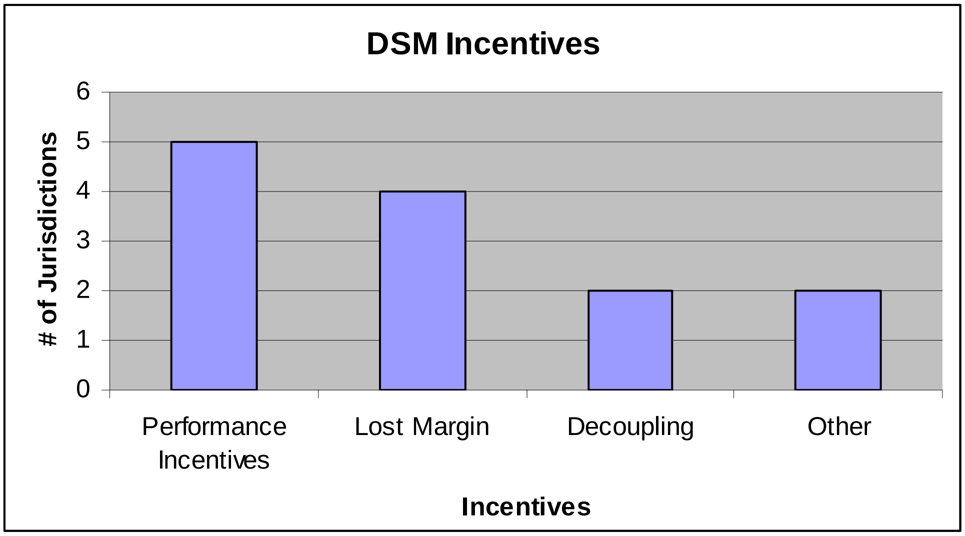
Figure 1. Efficiency Funding Sources



Among the interviewed jurisdictions, most states expense their efficiency costs. British Columbia is the only jurisdiction that capitalizes all expenses, although some states capitalize a portion of DSM expenses, such as demand response programs (New Jersey) or some amount of gas DSM (Vermont, Oregon). Utilities generally collect funds earmarked for efficiency and hold them in deferral accounts, from which expenses are drawn as needed. Accounts are balanced periodically. In states where efficiency is implemented by a statewide entity (New York, Oregon, Vermont), funds are submitted to the efficiency implementer or held in ESCROW until needed.

A variety of performance incentives and other mechanisms are used to encourage DSM in 10 jurisdictions. Connecticut, Massachusetts, Minnesota, Ontario, and Vermont offer performance incentives for efficiency. Four jurisdictions allow some sort of lost revenue recovery, either for all electric DSM (Connecticut), for gas DSM (Ontario, Massachusetts), or for a portion of electric DSM (Vermont). One state, California, has removed utilities' disincentives to delivering efficiency by decoupling profits from sales for both gas and electric sectors. Oregon has decoupled profits from sales for one gas utility. One jurisdiction interviewed (BC) reports the use of performance-based regulation, and one jurisdiction (Washington) imposes fines on one utility for failing to meet savings targets.

Figure 2. DSM Incentives



Only four of the jurisdictions interviewed for this study were offering incentives to utilities to implement DSM programs—Connecticut, Massachusetts, Minnesota, and Ontario. Vermont only provides incentives to the central agency. Both Connecticut and Massachusetts offer incentives for a range of achievement of goals, between 70 and 130% for Connecticut and between 75 and 110% for Massachusetts. Minnesota will provide incentives once 91% of the goal has been achieved, whereas Ontario provides a simple incentive of 5 per cent of net TRC benefits. In Massachusetts shareholders may earn up to 5% after tax return on the annual expenditures, subject to the level of performance achieved by the programs, which has become a fairly complex calculation to ensure that various goals are met.

The specifics of DSM incentives vary significantly across jurisdictions. A 1995 report stated that "current practice in DSM incentives varies widely"[22] and that remains true today. Appendix B to this report contains language from several regulatory decisions that were identified during the course of this project that can illustrate how these specific DSM incentives have been designed..

3.4 Factors Driving Interest in DSM

This section discusses the level of interest in DSM in Canada and the US and how this may vary between areas in which deregulation has occurred and those areas which are still served by vertically integrated utilities. As mentioned previously, the study team conducted interviews in jurisdictions judged to have a

[22] This report, while authored a number of years ago, still contains a good discussion of DSM incentive issues. See: Stoft, S., J. Eto, and S. Kito, "DSM Shareholder Incentives: Current Designs and Economic Theory". Energy & Environment Division, Lawrence Berkeley Laboratory, LBL-36580, January 1995

relatively high interest in DSM based on recent activity. Due in part to this selection of jurisdictions, Only two jurisdictions, Illinois and Texas, were self-described as having a modest or steady interest, respectively, in DSM. The interviews covered a wide variety of jurisdictions, including both traditional and deregulated energy sector structures. However, there were no indications that a jurisdiction's restructured status determined the level of interest in DSM. Nor were there any significant differences found in terms of DSM drivers, types of programs, and approaches.

Deregulated		***Traditional***
California[23]	New York	British Columbia
Connecticut	Ontario	Iowa
Illinois	Oregon	Minnesota
Massachusetts	Texas	Vermont
New Jersey		Washington
		Wisconsin

Several areas have had a long-term interest in DSM: California, Washington, and Oregon in the West, New York, New Jersey, and the New England states in the East, and Iowa, Minnesota, and Wisconsin in the Midwest. Interest in electricity DSM is generally much higher than in natural gas, although increasing gas prices recently have been reflected in an increasing interest in gas DSM (mentioned in about half the jurisdictions). And interest in electricity DSM has also increased recently, again in about half the areas studied, mainly due to high energy prices, environmental concerns, or supply and transmission issues. Most persons interviewed noted several drivers for interest in DSM, generally a combination of factors shown in the table opposite.

Drivers for Interest in DSM

High Energy Prices: DSM is a more cost-effective resource, lowers bills, and provides a hedge against risk and market volatility.

Environmental Concerns: greenhouse gases, other air pollutants, non-attainment issues and the desire for 'greener' solutions..

Supply and Transmission Issues: potential shortages this winter, growing peak demand, transmission constraints, congestion-related charges, reliability issues, generator retirements, reserve margin concerns.

Other Economic Benefits: job creation and net economic benefits due to energy bill savings, new technologies, and increased energy service company activities

3.4.1 Role of Stakeholders in Driving Expanded DSM

The entities that drive expansion in DSM activities is truly diverse. Most prominent as a key supporter are environmental interveners; they almost always take a proactive stance with regard expanding DSM activities. In addition, there is a set of organizations such as the American Council for an Energy-efficient Environment (ACEEE) that actively supports DSM throughout North America. The ACEEE has spun off regional entities that continue to press regulators, utilities, and legislative bodies to consider DSM as a resource. Beyond these common supporters, the surveys showed the utilities could lead the issue. Regulatory bodies seeking least cost plans for meeting customer needs were often leaders. Province/State governments also were leaders in a number of jurisdictions examined with legislation used as the vehicle to expand DSM activities. The level of interest in DSM by a high-level champion (CEOs in BC Hydro,

[23] Partially restructured.

and governors in California, Iowa, and Illinois) can have a significant impact on DSM activities. The table below shows the number of jurisdictions noting specific groups who are driving DSM.

Who is driving the interest in DSM?	# Jurisdictions citing
Political (government, legislature)	13
Interest Groups (customers, vendors, etc.)	11
Regulators	8
Utilities	7

The regional energy situation can also lead to increased interest by these stakeholder groups. The price spikes that occurred in a number of areas in 1999 and 2000 increased interest, supply shortages drive the search for cost-effective solutions, and the overall increase in energy prices during the past two years is another factor.

3.4.2 Types of DSM Programs and Delivery

This section looks at how DSM programs are being delivered in different regions and the types of DSM programs that are being promoted.

Approach to Electric DSM – Delivery

In general, the utilities – with or without third party contractors – plan, design, implement, and evaluate DSM programs, with regulators providing review and approvals. Most program administrators receive significant input and guidance from stakeholders and technical experts. Examples include formal advisory board arrangements, formal or informal public processes, or technical advisory groups or consultants. The term “collaborative” is often used to described the on-going group of stakeholders, including the administrator, that provides input to the administrator and the regulator.

	Utilities	Independent Administrator	3rd Party	Regulator/ Government
Plan Generic Programs	All other jurisdictions + VT	NY[24], OR[25], VT[26]	NJ, WI	
Design Specific DSM Programs	All other jurisdictions	NY, OR, VT	NJ	TX
Approve Programs			NJ	All other jurisdictions
Implement Programs	BC, IL, IA, MN, ON, WA, CA	NY, VT	CT, IL, MA, MN, NJ, ON, OR, TX, WI	
Evaluate Programs	BC, CT, IL, IA, MN, ON, VT, WA		CT, MA, NJ, NY, ON, OR, WI, VT	CA, OR, TX, VT

[24] Through the New York State Energy Research and Development Agency (NYSERDA)

[25] The Energy Trust of Oregon

[26] Efficiency Vermont, the Energy Efficiency Utility

Several states have implemented a centralized approach to DSM. For example, New York's electricity and natural gas programs are provided through NYSERDA. In Vermont, in 2000, an "energy efficiency utility" known as Efficiency Vermont was established to deliver efficiency in the state. It is run by the Vermont Energy Efficiency Investment Corporation, a non-profit firm selected competitively for a six year contract; load management is provided by the utilities. Recently, VEIC was awarded a new six year contract beginning in 2006. In Oregon a non-profit organization, the Energy Trust of Oregon, was created in 1999 to administer electricity conservation and market transformation programs and promote new renewable energy. Natural gas efficiency responsibilities were added recently.

Some states are completely changing their approach to DSM. Efficiency Vermont's approach continues to evolve (see inset). And New Jersey, which used to deliver natural gas and electricity DSM through the utilities, has established an RFP process to hire third party contractors to provide DSM and renewable energy.

Efficiency Vermont Approaches

Initial	Program based (e.g. Residential Low Income)
2002	Service-oriented (targeted market segments)
2006	Market-based (remove market barriers)

An influential organization for the delivery of DSM programs known as market transformation programs has developed in the Pacific Northwest. The Northwest Energy Efficiency Alliance (NW Alliance) spans Oregon, Washington, Idaho, and Montana. This is a unique organization in that it was set up to implement programs that were viewed as regional in nature. Some programs naturally cut across utility service territory boundaries and it may be inefficient for individual utilities to each set up the infrastructure to implement similar programs. The Northwest Energy Efficiency Alliance is a non-profit corporation supported by electric utilities, public benefits administrators, state governments, public interest groups, and energy efficiency industry representatives. The NW Alliance tends to implement market-wide and market transformation programs while the individual utilities continue to implement what have been termed resource acquisition programs that are more easily targeted at their customer base and service territory.[27]

A few states, such as Massachusetts and Wisconsin, try to make "market transformation" a key component of many or most energy efficiency programs, both for natural gas and for electricity. Other states, such as California and Washington, are facing supply constraints and have taken a "resource acquisition" approach to programs, in which efficiency is treated as a supply-side resource. These states emphasize programs whose main purpose is to get concrete energy and demand savings impacts, for example, by replacing inefficient equipment through use of rebates and incentives. In California and Vermont, resource acquisition is increasingly done by market-based approaches, in which utilities identify and eliminate barriers to efficiency that exist in the marketplace. Methods used in this approach may include offering rebates to customers, ensuring that efficient products are readily available for sale, and educating contractors and salespeople.

Approach to Electric DSM – Types of Programs

Utilities or DSM program administrators in most jurisdictions offer a combination of electric energy efficiency programs, load management, and demand response programs. However, the number of programs offered and the range of DSM measures covered by the programs varies considerably between jurisdictions. Several jurisdictions such as Massachusetts and Washington offer few or no load

[27] These diverse entities support the NW Alliance and work together to make affordable, energy-efficient products and services available in the marketplace. More information on the NW Alliance can be found at www.nwalliance.org.

management or demand response programs through the utilities or distribution companies. Massachusetts is in the New England ISO which does offer a number of ISO programs, but the utilities in New England (now restructured in to distribution companies) do not generally play a large role in the ISO DR programs.

Approach to Gas DSM – Delivery and Types of Programs

Natural gas DSM, if done, is generally done on a much smaller scale than electricity, usually focusing on weatherization and heating applications. In Ontario, however, the two large natural gas utilities have large customer programs and are quite different than most other U.S. utilities. Illinois is only beginning to look at natural gas DSM; the Governor's proposed Sustainable Energy Plan issued earlier this year had no provisions directly concerning natural gas. Six states treat electricity and natural gas in a similar fashion: California, Iowa, New Jersey, New York, Oregon, and Washington. In Iowa and Washington several of the utilities provide both natural gas and electricity. In the other eight jurisdictions studied they are treated differently, particularly in terms of type and level of funding. For example, in Minnesota electric utilities spend 1.5 to 2% of revenues on DSM and gas utilities spend only 0.5%, and in Connecticut gas DSM programs focus on low income consumers. Massachusetts relies heavily on natural gas for both electricity generation (30%) and space/water heating (60%) but funding for gas efficiency programs continues to be determined by regulators on a case-by-case basis. Electricity is funded by the SBC ($120 million/year) and emergency legislation was passed in Nov 2005 to extend funding to thru 2012. Natural gas DSM spending is between $20 and $25 million/year. However, both gas and electric programs focus on market transformation.

In Ontario, natural gas DSM funding and evaluations have been done through rate cases, a process which has been both time consuming and costly. For the new electricity DSM programs, the regulator is trying to avoid these issues by using guidelines and pre-specified variables for measures, including free riders, persistence, incremental costs, etc. In Oregon the regulator and the gas utilities are beginning to discuss distribution system optimization and DSM. For example, Cascade has constraints in Washington State, due primarily to transporter customers.

Approach to Demand Response Programs

Demand response (DR) programs range from Time of Use (TOU) and Real-Time Pricing (RTP) pricing (Illinois, British Columbia, Washington), and demand bidding (Minnesota, Oregon, Wisconsin) through to a complex offering of programs like in California (DBB, CPP, etc.). Demand response is a strategy that is growing in prominence in California. In response to the energy crisis in 2001, the IOUs began to implement a wider array of offerings, such as critical peak pricing and a "Flex Your Power" marketing campaign, still in use, that encourages all customers statewide to use less energy during peak periods, either by switching usage to off-peak hours or by reducing usage entirely. During the last few years, the IOUs have piloted and implemented programs ranging from TOU to advanced metering initiatives. At times the number of potential programs has been confusing to customers. Currently the IOUs and the CPUC are examining the results of these programs and looking to simplify offerings, make them more customer friendly, and ramp up the most promising programs.

In jurisdictions where there is an independent system operator such as PJM (New Jersey), NYISO (New York), NE-ISO (Massachusetts, Connecticut, Vermont), IESO (Ontario), or ERCOT (Texas), utilities often help customers to participate in those programs. Sometimes utilities also provide DR programs as in Connecticut and Ontario. In New York, DR is delivered both through NYSERDA and the NYISO. The Governor's

In Vermont, IOUs can establish contracts with customers who want to participate in ISO demand response programs, but there have been concerns about the programs and participation has been limited.

Coordinated Demand Response Working Group includes the New York Power Authority, Long Island Power & Light, the New York State Dept. Public Service, and NYSERDA.

Approach to Determining Spending Levels

In all the jurisdictions surveyed, the appropriate level of spending is set either by statute or by the regulatory body. In British Columbia, however, BC Hydro determines what electricity DSM programs are cost-effective and the appropriate level of spending.

Who	**States/Provinces**
Legislature	Connecticut, Massachusetts (electric), Minnesota, New Jersey, New York (electric), Oregon (electric), Texas, Vermont (electric), Wisconsin
Regulators	BC (gas), Illinois, Iowa, Massachusetts (gas), New York (gas) Ontario, Oregon (gas & electric), Vermont (gas), Washington
Utility	BC (electric)

4. REGULATORY CHOICES

The scan of DSM issues across jurisdictions, which included the interviews for this project, information shared with us by government and utility DSM officials, and our own experience with energy efficiency and demand response, provides insights into lessons learned concerning natural gas and electric energy efficiency programs. There are a lot of factors associated with a successful DSM effort – that is the reality in the jurisdictions we examined, and illustrates why regulatory orders in energy efficiency dockets tend to be quite lengthy.

This section builds on the more general discussion contained in Section 3 to examine choices that face regulators when working to develop or expand the role of DSM to help meet the energy needs of a region. These are posed as issues that need to be addressed by regulators followed by a discussion and recommendations.

ISSUE 1: SETTING APPROPRIATE TARGETS FOR THE AMOUNT OF DSM

Determining the appropriate level of DSM is one of the most challenging tasks facing any utility, jurisdictional, or regional organization. The interviews indicated that there was no single approach taken, but in many cases the results are similar in terms of the rough size of the energy savings targeted and the dollars allocated, sometimes as a percent of total revenues.

Issue 1: Discussion – Appropriate DSM Targets

The interviews indicated that this issue draws the opinions of a large number of stakeholders, each with a different reference point for making recommendations. In most jurisdictions, the ultimate decision represented a political compromise in the context of multi-variable negotiations involving environmental issues, customers' electric and gas rates, revenue for renewables, needs of different customer classes, and funding required for a target level of energy efficiency and load management. Jurisdictions that do consider the issue substantively seem to have a set of common themes:

Factors Influencing DSM Targets and Expenditures:

- Estimation of the total available resource for EE is generally developed through a technical potential study. Given changing market conditions, a number of states have updated technical potential studies[28] which were completed many years ago[29] and are using them to adjust the target DSM levels. These studies take into account a region's building stock, baseline levels of efficiency that already exist, a forecast of how baselines might change over time, electric and gas prices (higher prices will support a larger amount of DSM), and cost of other resources that could also meet energy needs (e.g., supply-side options and renewables)

[28] British Columbia is beginning the process of updating the technical potential study for that region, and Oregon is undergoing such a study right now. California, Iowa, Minnesota, New Jersey, New York, and Vermont are other states that have conducted technical potential studies in the past few years.

[29] The debates through the 1990s over whether to restructure a region's electric industry and how it should be restructured diverted the focus on DSM. Generally, rates were stable during this period and many believed the competitive retail market would provide DSM on its own to customers as part of bundling commodity and services. A number of states were not fully convinced of this argument and set Societal Benefits Charges (SBCs) which were mills per kWh fees paid into an account used to advance different DSM initiatives.

- The future need for additional resources. Some jurisdictions set DSM targets to meet a given percent of future load growth.

- The existing infrastructure to deliver programs and what changes might be required to deliver the target level of the DSM resource. Building up required infrastructure, training trade allies in EE design, maintaining a reliable supply of certified contractors, and working with suppliers to develop the availability of EE materials has been one of the most important aspects of sustaining a long-term commitment to DSM.

- A DSM plan that ramps up programs in different sectors over a period of time beginning with programs that represent “lost opportunities.” These are generally new construction programs since it is much cheaper to build in energy efficiency during construction than it is to retrofit.

- The need for processes to assess DSM accomplishments and to perform analyses that help ensure that DSM is delivered in the most cost-effective manner possible.

Even jurisdictions that have undertaken these substantive analyses can arrive at different conclusions. For example, the DSM target for Texas is to meet 10% of new load growth each year (with annual reports required), while Illinois has a Sustainable Energy Plan that calls for increasing percentages each year starting in 2007. The Illinois Commission will also tolerate a maximum percentage rate increase per year of 0.5% to obtain the load reductions. The time table for the Illinois Sustainable Energy Plan calls for:

- 10% of Projected Annual Load Growth to be met in 2007/2008;
- 15% of Projected Annual Load Growth to be met in 2009-2011;
- 20% of Projected Annual Load Growth to be met in 2012-2014; and
- 25% of Projected Annual Load Growth to met in 2015-2017.

Other approaches for setting targets, as discussed in Section 3.1, use an expenditure amount tied to a percentage of total electric revenues. These include:

- Minnesota where the largest utility (Xcel Energy) must spend a minimum of 2% of revenues on DSM;
- Oregon with a Public Purpose Charge of 3% for the two major electric utilities;
- TXU, an IOU in Texas which has to meet 10% of load growth each year by DSM. TXU spent about 2% of annual revenues, though that is not how the target was determined;
- Vermont has set spending caps[30] that changed each year, but the end result is that they spent about 3% of electric revenues for DSM. 3% was not the target but about how much was actually spent;
- Wisconsin targets 3% of electric revenues; and,
- Utility representatives for PG&E in California estimate that spending on electric efficiency in 2004 and 2005 has been between 2.5% and 3% of electric revenues.

While the process and rationale for setting these targets varied substantially in each jurisdiction (see Section 3.1 and Appendix A), DSM expenditures for a number of major utilities and jurisdictions vary

[30] This 3% cap on spending in Vermont has been lifted in 2005 and new funding levels have not been established.

between 2% to slightly above 3%.[31] In several cases, even spending 3% of revenues on DSM was not enough to capture the identified cost-effective DSM in the offered programs. For example, Vermont found there were additional energy efficiency projects and customers in the pipeline that could not be captured under the 3% funding cap.

Issue 1: Recommendations – Appropriate Targets for DSM

There are several considerations viewed as important in setting targets. First, targets should cover a period of time that allows for ramp-up of DSM programs and development of the appropriate infrastructure for resource acquisition and market transformation programs. Second, a minimum level of expenditure can be established such that the amount dedicated to energy efficiency is sufficient to build and maintain a critical mass of infrastructure within markets program capacity; and, over time, the amount should never go so low that critical capacity (i.e., qualified contractors, trained employees) is eliminated. In Vermont, when Efficiency Vermont was created, this minimum amount was thought to be roughly a 1.5% surcharge on rates. Program budgets were ramped up from there after the first year (2000) to the current level of roughly 3.0% of rates in 2005.

There are a number of ways to set the final amount. It can be set administratively, as in many restructured states. This would typically be a rough round number approximating what policymakers felt consumers could afford, informed by how much was spent on energy efficiency in the past. This is simple, and in jurisdictions where energy efficiency stirred some of the more contentious regulatory disputes (owing to the throughput incentive), the relief from fighting is just as welcome as the secured commitment. But this approach has a long term problem—energy efficiency is disconnected from other resources that are serving customers. There is no assessment as to whether all cost-effective energy efficiency is being achieved. The program becomes like a government program, in which managers get a budget and do their best to manage within it, without necessarily considering fundamental questions about the size and purpose of the program.

In most states and provinces where energy efficiency programs exist, at one time or another a resource-driven process was used to set energy efficiency budgets. In some states, spending has not returned to the nominal levels of the early 1990s (i.e., not accounting for inflation) despite higher avoided costs today. To really know the appropriate spending level for energy efficiency, some regulatory process in which energy efficiency and other resources are evaluated together is necessary. For some, the term integrated resource planning (IRP) is loaded and connotes a burdensome process.[32] Good best examples today of an unconstrained process in which all cost-effective energy efficiency is available are the Northwest Power and Conservation Council and the California IOUs.

A key issue in each jurisdiction, not always explicit, is resolving the conflict between wanting to procure all cost-effective energy efficiency and concern about the resulting immediate effect on rates. In many jurisdictions, it is evident some compromise was struck, allowing for a significant yet limited rate impact

[31] While BC Hydro was quite explicit in stating that they did not use expenditure targets to determine the level of DSM, i.e., their goal is to implement all cost-effective DSM given practical considerations in terms of what could be rolled out. However, a calculation of what BC Hydro spends on DSM compared to revenues showed that approximately 3.3% of revenues was spent on DSM.

[32] Some participants in IRP processes of the early 1990s viewed them as overly burdensome simply due to the number of combinations of supply-side and demand-side alternatives that some stakeholders wanted examined. There is the curse of dimensionality in resource planning since there are a nearly infinite number of combinations of resources that can be used to meet future load growth. As a result, a resource planning process needs to have a good screening phase such that only those combinations of supply-side and demand-side resources that are likely to be components of a least-cost resource plan are actually evaluated in the modeling phase of the work.

to support a meaningful suite of programs. Budgets based solely on findings from an IRP, or from a benefit-cost assessment would come down squarely on the side of accepting whatever rate effects are necessary to secure a long term overall resource plan—energy efficiency might enable fewer kWh to meet the region's energy needs but at a somewhat higher price for each kWh.

For an overall recommendation, the scan of jurisdictions that have been implementing DSM for several years seems to indicate that:

1. *A minimum expenditure of 1.5% of annual electric revenues*[33] *might be appropriate with a ramping up to a level near 3%.* These figures are irrespective of whether a jurisdiction has adopted retail electric competition or imposed generation divestiture, though regulatory oversight details may be quite different in either case.

2. *Higher percentages may be warranted if there is expected to be rapid growth in electric demand or an increasing gap between demand and supply due to such things as plant retirements or siting limitations.* Even those states with 3% of annual revenues as an expenditure target have found that there have typically been more cost-effective DSM opportunities than could be met by the 3% funding.[34]

3. *For gas utilities, the expenditure levels have been found to be lower in virtually every jurisdiction examined.* No good reason was given for this in the surveys conducted other than that gas has not received as much attention as electricity in analytic studies. Still, gas space heating and water heating, as well as industrial uses, can benefit from DSM efforts. Given the history observed through the interviews, a recommendation of a range of 1% to 2% for gas DSM seems more consistent with industry practice than the minimum recommendations of 1.5% to 3% for electric DSM.

4. *These DSM targets should be reviewed periodically.* California calls for a review every three years, Texas requests annual DSM forecast and filings to ensure the 10% of growth is being obtained by the DSM programs offered, and Idaho and British Columbia conduct an IRP update every two years. This is important to update avoided costs used as the benchmark for determining cost-effective DSM, and to incorporate any unforecasted events (e.g., the recent rise in the price of natural gas) that might change the economics of DSM versus other resources. The review should take into account the importance of maintaining a critical mass of basic capacity within markets for implementing energy efficiency programs, such as contractors, craftsmen, and trade ally relationships.

---

[33] Electric revenues for an integrated utility would include commodity, transmission, and distribution since DSM can have avoided costs in all of these operating areas. For a restructured industry, the percent would be based on those elements of the bill that address commodity, transmission, and distribution.

[34] In some cases these expenditures have been tracked by rate class such that contributions by, for example, the large customer class are used to fund DSM programs for those customers. This potentially addresses some equity issues, but is clearly less efficient overall in that if there are more cost-effective DSM opportunities in the commercial sector then the least cost plan would distribute the funding such that kWh are saved at the lowest possible cost. In the long term, this should be the best plan for all customers as overall costs of electricity would be lower. However, some consideration towards equity in who pays for the DSM programs is appropriate. Some states provide an opportunity for certain customers to opt out of SBC payments for DSM programs. For example, New York allows larger customers to opt out of paying the SBC rider, but then they cannot participate in any of the offered DSM programs at any of their facilities. In general, the common belief is that there are adequate opportunities for energy efficiency across all segments and it is not recommended that some customers be given the choice to opt out.

ISSUE 2: COST RECOVERY OF DSM EXPENDITURES

Cost recovery of expenditures is an important factor for organizations that are spending monies and implementing DSM programs.

Issue 2: Discussion – Cost Recovery

Most utilities and regulators prefer the practice of expensing energy efficiency costs; in the long run, this approach costs less than capitalizing—deferring and amortizing—costs. The only exception is in cases where programs are being started from scratch, and decision-makers are worried about rate impacts. Capitalizing energy efficiency costs from a period of one year to the average lives of the program measures is done in some jurisdictions. This practice does reduce the immediate cost to implement programs, but there are problems. The carrying cost (at the utility average cost of capital, 7-9% these days) of the unamortized balances adds cost to consumers, quite a lot if the amortization period is long. Eventually, consumers are paying each year's amortized balances, which add up to the annual amount spent on efficiency, plus the carrying cost. Utilities are also concerned about increasing "regulatory asset" balances, assets on the utility books not backed by actual equipment. Once this practice starts, it is hard to convert to expensing, again due to rate impact concerns.

Issue 2: Recommendation – Cost Recovery

The practice of expensing the costs of DSM programs, possibly through a balancing account, seems to be an acceptable approach. However, there are probably a number of approaches that may be acceptable to parties. If near term rate impacts are a concern, capitalizing a portion of the costs may be appropriate. Also, if the DSM targets are based on a percent of electric revenues, the revenues that flow to the implementing organization may need to be levelized since they may be higher in winter or summer, yet implementation of DSM programs may be steady and even increasing in spring and fall in preparation for the cooling or heating season. In general, different jurisdictions have been able to address issues of cost recovery once a DSM target is set. Of greater interest is how potential disincentives (e.g., lost revenues) are treated.

Early energy efficiency programs were fully integrated into utility budgets and finances. In the transition to retail electric competition, many states decided to separate energy efficiency funds from the rest of the funds to run the utility. A system benefit fund, such as a Systems Benefit Charge (SBC), was set up with money collected as a surcharge from consumers for the purpose of paying for public purpose programs like energy efficiency.

In some states, these separate funds became targets for legislative appropriators in times of tough budgets who found ways to siphon these monies away from their intended purpose to support general government. While it is unwise to suggest that a state legislature cannot do something, these experiences suggest it is advisable either to avoid creating a system benefit fund, especially if utilities will continue to administer programs, or to create explicit legislative intent that states the purpose of the fund and prohibits funds from being used for other purposes. Vermont has such language, and has thus far avoided losing any funds to the appropriations process.

More fundamental to the question at hand is the fact that states with system benefit charges allocating an automatic or formulaic budget to energy efficiency create a disconnect between DSM funding and other resource decisions being made by utilities and regulators. This underscores a point already made, that a regulatory process that compares the values of all resources benefits consumers. Updating DSM plans is important either when using a resource planning process or a benefit-cost analysis based on updated avoided costs. Setting a SBC charge and not periodically analyzing this charge would pose planning risks and decrease the flexibility to address unexpected events through DSM programs, a key component of the value of DSM investments, i.e., the portfolio diversification and risk mitigation.

ISSUE 3: ADDRESSING INCENTIVES AND DISINCENTIVES FOR DSM

Organizations that traditionally earn profits from selling a product are now being asked to work with their customers to help them use less of their product which lowers the organization's overall revenues and potentially lowers its profits.

Issue 3: Discussion – Incentives and Disincentives

Most jurisdictions with successful energy efficiency efforts recognize the tension of the throughput incentive, the link between sales and net income (profits) that is an inevitable outcome of traditional regulation.[35] To illustrate its influence, a 5% decrease in sales for an integrated utility leads to a 25% reduction in net profit. For wires-only companies, the effect can be nearly double. Government or consumer-owned utilities have similar concerns. Even though they do not earn "profit," they must pay attention to debt coverage and are concerned (along with their bondholders and lenders) that revenue erosion from reduced sales can hinder debt repayment. The throughput incentive, where it exists, is identified universally as a barrier, and maybe the key barrier, to effective energy efficiency deployment. Yet, as the long-standing method of regulation that is well understood by participants, there can be overwhelming reluctance from utility and regulatory staff to change.

Some jurisdictions return lost margins to utilities, sometimes as a result of a regulatory proceeding that produces a precise accounting based on evaluation of program accomplishments in terms of saved kWh. Regulatory proceedings to calculate lost revenue adjustments can be time consuming and contentious, often due to debates over the accuracy of the evaluation of saved kWh, unless there is a clear process that is easily implemented.

Some states (e.g., Oregon, Maryland, and California) have changed the way some utilities make money, decoupling sales from profits, by keying utility revenues to something other than sales, such as number of customers. This approach is effective, and has the advantage of opening the utility to consider all cost-effective measures that might lead to reduced sales (efficiency, demand response, customer-owned generation) without concern for eroded profits. A revenue cap approach can also explicitly build in ways to share risks between consumers and utilities of unseasonably hot or cold weather, volatile commodity prices, or economic downturns. In this approach, there is no reason to change the customer rate design, at least not for the purpose of changing utility incentives (regulators may wish to change rate design to influence consumption patterns, which will be discussed later).

Some industry advocates suggest a different form of decoupling. The idea is that rate design is shifted such that more money is collected via the fixed portion of the rate, and less is collected in the variable portion. The rationale is that utilities will be more open to energy efficiency if they do not have so much revenue dependent on the commodity charge. As we have just seen, a better way to avoid commodity charge dependence is to connect revenues with numbers of customers, and this way also preserves the long run marginal cost pricing signal to customers that maintain the message to conserve.

[35] A more detailed discussion of this issue of incentives and disincentives in the delivery of DSM can be found in the Regulatory Assistance Project Newsletter, "Regulatory Reform: Removing Disincentives to Utility Investment in Energy Efficiency," September, 2005. (Available at www.raponline.org).

Finally, there are a number of states that offer positive incentives for attaining the DSM goals in terms of sharing the benefits of DSM between customers and rate-payers. This was discussed in Section 3.3. Five jurisdictions (Connecticut, Massachusetts, Minnesota, Ontario, and Vermont) offer performance incentives for meeting or exceeding specified efficiency targets. Performance goals and incentives can be used independent of the throughput issue. Goals can be an organizing focus for energy efficiency staff, and linking achieving these goals with some financial reward allows a connection to employee bonuses and a shareholder benefit. In addition to the program incentives just mentioned, there are other financial ways regulators can signal to utilities that energy efficiency is a priority. Appendix B contains language from several regulatory decisions pertaining to DSM incentives.

One way is to assure that investments in energy efficiency appear on the utility books in a way equivalent to an investment in a power generator or a transmission line. A drawback to this approach is the difference in control that the utility has between the owned, tangible asset of a generator and a "regulatory asset" represented by the capital spent, but not by a hard asset. As long as the investment community is comforted that rates will be set to recover the costs of these investments, there should be no substantive difference, but utilities are likely to want to limit the amount of regulatory assets on their books.

A more simple way to reward a utility for a job well done on energy efficiency is to add basis points to the cost of capital used to set rates. Investor owned companies can allocate some of these funds directly to shareholders. In the case of a publicly owned utility or an IOU, this revenue from customers can be used for performance incentive pay for employees involved in the successful programs.

Issue 3: Recommendations – Incentives and Disincentives

The issue of lost revenues and potential disincentives to utility investment in DSM has been a contentious issue in a number of jurisdictions, even though it is undoubtedly true. If the utility or distribution company sees sales decline over what would have been the case, then they must not be earning the same level of revenues and profits. Nevertheless, this disincentive is real and should be addressed either through an adjustment clause that tracks and makes the utility whole (or mostly whole) for lost margins due to lower revenues, or through a decoupling option to eliminate this disincentive. The overall recommendations are:

1. *Lost margins due to lower sales of electricity and/or gas should be addressed such that it is not a disincentive to utility investment in DSM.* This can be accomplished through a reconciliation procedure[36] or a decoupling of revenues by tying them to the number of customers and weather adjusted sales.

2. *Where additional incentives for meeting or exceeding DSM targets have been used, the impact on the utility and its rate-payers appears to be positive.* The incentive now provided to Massachusetts distribution companies, for example, is not overly large, but it does capture the attention of management and helps create best efforts for cost-effective DSM (See Appendix B).

[36] It is important that lost revenues not be allowed to accumulate over a large number of years. When a rate case is held, all the balancing accounts are addressed and reset at zero. If there is a long period between rate cases, the lost revenues adjustment can grow to be as large as the total expenditures on DSM; this happened in Vermont and a similar situation occurred in Massachusetts. To address this, Massachusetts simply limited lost revenues to a rolling three year average such that this balancing account was zeroed out every three years and reset. Such a process should be implemented if a lost revenue adjustment mechanism is to be used.

ISSUE 4: BENEFIT-COST TESTS AND AVOIDED COSTS

Assessing and evaluating DSM accomplishments is important on a prospective basis to develop a cost-effective mix of DSM programs, and on a retrospective basis, benefit-cost analysis is needed to discern whether the expected benefits from the DSM programs were actually obtained. These retrospective studies also can be used to develop a more cost-effective mix of DSM activities and provide suggestions on how to make a specific program more effective (see Section 3.4).

Issue 4: Discussion – Benefit-Cost Tests

A jurisdiction reveals its view on the purpose of energy efficiency by the benefit – cost tests it uses to evaluate programs and measures. Use of the Ratepayer Impact Test (RIM) indicates a strong interest in the satisfaction of individual consumers, but ignores the resource and societal values that flow to all along with the obvious value to the program participant. Many widely used energy efficiency programs do not pass the RIM Test.

Use of the total resource cost (TRC) test instead of a societal test values the economics of energy efficiency compared with other sources, but values at zero other advantages to society that, though perhaps hard to quantify, are worth more than zero. These other advantages may flow from avoided air pollution, water use, or reduced risk from avoided capital construction of generation and transmission, for example. Use of the societal test to evaluate energy efficiency programs represents a view that all effects of energy efficiency programs are important. Precision in the societal test is elusive, and jurisdictions that use it sometimes apply a rough “adder” or “multiplier” to handicap other sources in comparison with efficiency.

Accurate valuation of energy efficiency requires reasonable assessments of system avoided costs. Such assessments must be updated from time to time, and provide a valuable benchmark for managing energy efficiency activities. A valuable element to this process comes from gaining knowledge about the shape of the utility’s hourly load curve. Programs that produce savings in particularly valuable hours have more value to consumers.

With increasingly regional electricity markets, stakeholders in New England and, separately, in California, are collaborating on an avoided cost analysis framework that many will share. As a practical matter, the avoided cost assessment matters most if energy efficiency budgets are actively managed and are set based on this assessment. If a set amount of dollars is allocated to efficiency, the challenge becomes how best to use those funds, so avoided cost still remains important for program evaluation.

Further study of energy efficiency value is underway in several states. Utilities are considering the ability of EE (and other distributed resources) to avoid or delay load growth that would otherwise lead to investments in upgraded transmission and distribution, in addition to new generation already captured in most avoided cost calculations.

Another facet of benefit-cost is the prevalence of “potential studies.” A potential study provides useful intelligence, telling a decision-maker how much energy efficiency is available from among the regularly occurring “opportunities” and the accumulated “retrofits.” Recent studies in the Northeast U.S. indicate the potential of such quantities that annual energy use could be reduced year after year with a modest increase in spending from current levels. The only downside of a potential study is the expense – $250,000 to $500,000 or more for a comprehensive regional study. However, as discussed previously in Section 3.1, DSM potential studies can be designed to meet multiple objectives. Information from a DSM potential study is often used as the first step in design of programs since such studies can document current practice and establish energy use baselines. This information can also be used to design an appropriate program for a region and help establish initial customer/trade ally incentives and marketing messages.

Issue 4: Recommendations – Benefit-Cost Tests

The use of benefit-cost tests reflects the importance that regulators in a jurisdiction place on different factors. This is one reason why the tests in common use today, the California Standard Practice Manual tests, incorporate five tests. As a result, there is no exact answer to the question about which test to use and how to construct that test. However, this effort provides the following recommendations for use of benefit-cost test:

1. *The primary test that should be used is the Total Resource Cost test applied to a portfolio of programs, with program specific tests used to address appropriate program design and the mix of programs in the portfolio.* For retrospective analyses, it is important to understand that delivering a DSM program is like introducing a new product into a market: the customer needs to become aware of the offering (marketing), be brought to the point where they are willing to act (sales), and there must be the follow-through delivery of the program (fulfillment). Some programs will likely work better than expected, while other programs will encounter problems that need to be rectified. As a result, it may be unreasonable to expect all the programs to pass the TRC test, but the portfolio as a whole should pass the TRC test.

2. *The Participant Test should be part of implementation to ensure that customers that participate in the program do benefit, but should not have a significant role in setting overall DSM expenditure levels.* Rather, it is useful in the design of specific programs to ensure that the customer perspective in represented.

3. *The other tests commonly calculated can be used to provide different perspectives.* If there is a large discrepancy between a ranking of DSM activities based on the TRC test and one based on the RIM test or the Societal Test, then the planning process should be flexible enough to make adjustments. For example, a societal test may show that one program is much better from an environmental perspective (a cost commonly used in the Societal Test). Also, if one program drops substantially in its ranking (not in its benefit-cost ratio, but in its ranking relative to other programs); then, it may pose some equity problems across customers that could be corrected by making some adjustments in the program. In general, it is recommended that the TRC test be the guide, with the other tests used to see if there are extreme differences that might suggest some flexibility in the design of a DSM program or the mix of DSM activities.

4. *The benefit-cost tests need accurate estimates of avoided costs.* This means that this should include not only avoided costs of generation (i.e., the commodity cost), but also avoided transmission and distribution (T&D) costs. Progress is being made on determining avoided T&D costs in various states that have started to focus on this issue. It is recommended that the best estimates of avoided generation and T&D costs both be used in the application of these tests.

Issue 5: DSM Program Assessment, Monitoring, and Evaluation

Any investment of ratepayer funds should be the subject of ongoing assessment and verification to both provide assurances that anticipated benefits are being attained, and to provide feedback on the programs and their implementation such that they may be improved over time.

Issue 5: Discussion – Assessment, Monitoring, and Evaluation

Energy efficiency programs focus on barriers to consumers making these investments, and administrators should spend no more resources than needed to knock down these barriers. There are literally thousands of creative and good ideas to address these barriers that have been developed by program administrators and implementers in the U.S. and Canada. This section distills these into important messages.

Sometimes, all that is needed is information, and the customer will act. Sometimes, cash incentives are needed to defray the cost between what the customer would do anyway and the more efficient option. Sometimes, the supply chain does not put energy-efficient options in front of the customer, so programs that work with supply chains and trade allies are a critical element of a successful suite of programs. Sometimes, it takes creativity to identify “the customer” who makes the actual decision on energy matters in a business or in the construction of a new development. Deep familiarity with the energy market in the territory is very helpful to successfully answer these questions.

If customer incentives are needed, they should be set to get the desired savings at the desired price, and the incentives should be reduced as consumer acceptance grows; this pattern is evident in many states for retail discounts on compact fluorescent light bulbs. The concept of leveraging consumer funds and time is an important aspect to designing and managing programs.

Regulators expect program costs to be minimized. One way this happens is by focusing resources on the moment when consumers are about to make a purchase or a commitment. Attention to these opportunities means many different things for different programs and customer classes in practice, but is generally an organizing principle behind many successful programs.

Many successful programs are characterized by staff particularly trained for selling. This sort of staff member is not always found in numbers in the ranks of utilities, yet working with customers large and small, trade allies, and others on energy efficiency in the end requires the skills to satisfy the customer and close the deal. A compensation system linked to program performance goals is an extension of this connection to traditional sales.

To help sales, federal agencies are continuing to develop the Energy Star brand which is meant to identify the top quartile of energy performing products. Energy Star is also being applied to whole buildings, reinforcing the benefits of this perspective. Most states use Energy Star as a standard in at least some of their programs. Energy Star is popular, and some warn that administrators may be tempted to use Energy Star too liberally, diluting its value as a brand used exclusively for the top echelon of energy performing products.

Low income residential consumers face distinct barriers to energy efficiency investments, among many barriers. Knocking down these barriers has significant societal value as part of a safety net to assure some minimum level of affordable comfort. Programs addressing low income consumers are universally available, and in most cases much lower benefit-cost ratios are allowed.

On a different end of the economic spectrum, large business customers in many states have gained some flexibility regarding their obligation to support energy efficiency programs. These customers argue that they operate in a competitive world and are highly motivated to secure cost-effective energy efficiency savings. In some states, these customers are given the opportunity to opt out of some or all of the charge they pay for energy efficiency if they can show that they spent to achieve significant results independently. There may be opt-out programs with merit, but it is important to remember that the charge for energy efficiency that all consumers pay goes in part to pay for the societal or total resource benefits that all consumers share. For this reason, it is appropriate that the opt-out still leaves a requirement to pay a portion of the charge (in Vermont, the opt-out customer still pays 30% of the full energy efficiency charge). Interestingly, there are also experiences when such customers are helped by specialists in their industry provided by program administrators to find energy efficiency opportunities missed by plant personnel.

Some jurisdictions take a "portfolio" view of energy efficiency. This recognizes that different programs have different benefit-cost ratios, and that some programs with strong social values may have a benefit-cost ratio of one or lower. With this approach, the target benefit-cost (let's say, 2) is based on all programs together, allowing programs with high ratios (3 or 4) to offset the results of programs with low ratios (1 or lower). This approach is useful if there is a strong linkage between energy efficiency programs and governmental priorities.

One program issue that has attracted significant attention over the years is fuel switching. This is an issue because there are many electric space heating and hot water heating customers, and it is sometimes cost-effective from a societal perspective to switch them to natural gas or another fossil fuel. The question for regulators is: should the regulator direct the electric utility as part of its energy efficiency effort to switch the equipment to natural gas (or other fossil fuel) and lose the end use in the process? A few states, including Vermont, tackled this issue in the early 1990s, but for the most part, this issue is dormant, and fuel switching is rarely a part of the current suite of efficiency programs.

The factors discussed above tend to focus on program implementation tactics and strategies and often are the subject of what has become known as process evaluations, i.e., are the existing programs being delivered efficiently and are they addressing the appropriate target market. In addition to these efforts, it is important to address how much energy is being saved by these DSM efforts.

States with successful programs appreciate that evaluation, measurement, and verification (EM&V) is vitally important. While it costs money that is not spent delivering programs and services, EM&V helps all stakeholders to maintain confidence that consumer funds for energy efficiency are appropriately managed and identifies possible improvements. Most EM&V activities are done by entities independent of the program administrator, either a contractor hired by the administrator or by the government.

There must be oversight by the regulator on the cost of EM&V to be sure it is not excessive. We can expect EM&V costs to be around 5%, at times up to 10%, at other times less of total EE program costs. How the EM&V is done affects the cost. Some states let the utility make the arrangements and others, such as California, forbid this utility approach to quality control. In Vermont, the state energy office and public advocate is responsible for EM&V. This approach has value since the public advocate is motivated by its overall mission to control costs, while, as the energy office, there is great expertise. Costs are also low in Vermont because there are few companies to review. For all, including the state approach, costs are covered by energy efficiency program costs, and are included in program benefit/cost assessments.

An important aspect of EM&V is the set of baselines used to evaluate success. Baselines refer to what would happen if the programs did not exist. Because equipment and appliances are getting more efficient, and because some consumers may be more likely than before to buy a more efficient model, it is important to regularly reassess and, if necessary, raise the baseline against which program savings are measured.

In each jurisdiction, the approach to measure savings is a little different. There is now an effort in the Northeast U.S. to resolve these into agreement, to the extent that is possible. National Grid, a company operating in four states, is hoping that this effort does not create a fifth protocol to worry about but is cooperating because consistency would simplify its administrative process. Canadian provinces may wish to encourage consistency in measuring savings.

One reason for valuing consistency is if there is any future plan to institute an energy efficiency portfolio standard among Canadian provinces. Such a standard would apply a requirement to produce annual energy efficiency savings of x % of load. Utilities subject to the requirement could meet it through its own programs, or purchase credits from others that over-comply and produce excess credits. Such a standard is under development in Connecticut and Pennsylvania. In each of these places, the challenge of creating a system to turn programs into credits such that a MWh from a lighting program is the same as a MWh from an industrial motors program is significant.

Consistency is also important if there is a chance that efficiency will create credits to address pollution or climate change requirements.

Issue 5: Recommendations – Assessment, Monitoring, and Evaluation

Delivering cost-effective DSM programs is more difficult than many realize. Marketing, sales, supply channel development, and fulfillment tasks each have to be addressed successfully. It is often the case that it can take more than a year for a DSM program to overcome these start-up issues and become cost-effective. This complexity in the delivery of these programs, along with the value of creative ideas in implementation, makes it important to assess these programs in terms of delivery processes on an annual basis. This can be done by using performance indicators initially, e.g., the number of participants, measures installed, and trade allies signed up. However. eventually an accounting of the actual energy savings attributable to the DSM programs will be needed to ensure that the expected benefits from DSM are actually being obtained.

California is in the process of adopting evaluation protocols[37] and, based on the interviews, BC Hydro has developed a state-of-the-industry evaluation approach. Other regions of the country have a long history related to the evaluation of energy efficiency programs. In New York, the New York State Research and Development Authority has conducted three years of evaluation of their SBC funded Energy $mart[SM] programs.[38] Many New England states, specifically Massachusetts, have helped pioneer the evaluation literature as their evaluations have had to meet the scrutiny required by the payment of incentives for the accomplishments of their program; many program specific evaluations have been filed with the Massachusetts Department of Telecommunications and Energy.[39] Given this extensive literature[40], the specific recommendations are:

1. *At program design and initiation, key success factors in terms of number of participants, measures installed, monies spent, trade allies signed up or participating (e.g., contractors for new construction), customer satisfaction, and a timeline for meeting these success goals need to*

---

[37] "The 2005 California Energy Efficiency Evaluation Protocols;" prepared for the California Public Utilities Commission, by TecMarket Works (and subcontractors), December 5, 2005. See: http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/evaluationreportingprotocol-2nddraftchangestracked.doc.

[38] "New York Energy $mart[SM] – Program Evaluation and Status Report;" Report to the System Benefits Charge Advisory Group; Final Report - May 2005. See: http://www.nyserda.org/Energy_Information/05sbcreport.asp.

[39] The development of guidelines for evaluation in Massachusetts began in the early 1990's. A landmark decision was issued in "Order Promulgating Final Guidelines to Evaluate and Approve Energy Efficiency Programs" D.T.E. 98-100, last modified on 27-Apr-2004. See: http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm.

[40] In the mid-1990s, the National Association of Regulatory Commissioners (NARUC) contracted for a report focused on regulatory issues in DSM evaluation. While somewhat dated, the unique focus of a regulator's perspective on evaluation still contains many insights that are relevant today and it was written when DSM activity was at its height in the United States. It is available from NARUC publications store at: http://www.naruc.org/storeindex.cfm?startrec=21 and the reference is: *Regulating DSM Program Evaluation: Policy and Administrative Issues for Public Utility Commissions.* NARUC, Washington, DC, NTIS Pubs. #ORNL/Sub/95X-SH985C, by Violette, D. and J. Raab; April 1994.

be developed. Many utilities or DSM implementers report some of these factors quarterly, while others may only be reported annually.

2. *Also at program design, the data collection to be used to assess energy savings will need to be incorporated into a program tracking system with customer IDs such that sites can be sampled as part of a monitoring and verification process.* These data will also be used to estimate overall program impacts, net of what would have happened without the program. These attribution assessments of energy savings may be performed annually for some programs, but only every two years with other programs. The key is to have an evaluation plan completed at program initiation so that all the data needed for evaluation will, in fact, be in the program records when it comes time to perform the evaluation.

3. *An approach used by BC Hydro approach is representative of current state-of-the-practice evaluation efforts*.[41] This consists of:

    - A complete evaluation plan is prepared at DSM program initiation.
    - The actual evaluations are conducted at major milestones or at program completion.
    - Process, market, and impact evaluations are conducted, and are overseen by a cross-functional DSM Evaluation Oversight Team.
    - In addition, for programs that include larger individual projects (i.e., > 0.3 GWh/year), technical and financial reviews are conducted before an incentive is offered to provide assurance that the technology is feasible, that the estimated electricity savings are reasonable, and that the cost-effectiveness is acceptable.

ISSUE 6: INTEREST IN DSM, LEADERSHIP, PRICING, AND OTHER FACTORS

This section ties together a number of other factors that are important and deserve to be addressed briefly.

Issue 6: Discussion – Other Factors Influencing DSM

Energy Efficiency Motivators

Apart from the policy and program details, it is evident that states and utilities are increasingly motivated to create and expand energy efficiency programs. This trend flows from the dilemmas and risks associated with supply resources, the experience of inexpensive energy efficiency in many jurisdictions from many program types, and environmental quality. Keeping consumer dollars circulating in local economies is also a factor in some places. These motivations have led decision-makers to engage in the initiatives, innovations, and upgrades to energy efficiency this report covers. Likewise, attention to meeting electric peak load and to creating electric wholesale markets is increasing interest in demand response programs.

Leadership

A common theme in jurisdictions active in energy efficiency is leadership. Leaders may be elected officials, appointed officials, or utility CEOs. Leadership is often challenged by advocates arguing for low

[41] An overview of this approach is in the Resource Planning Guidelines – http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf. More detail is available in BC Hydro filed evaluation plans and in "DSM Evaluation Summary and Plan; Appendix M" in BC Hydro, Revenue Requirement Application – 2004/05 and 2005/06 Volume 2, December 2003.

rates in the present while devaluing longer term benefits mentioned in the prior section. Statutes permit, and in some cases, drive leaders to push for significant and sometimes expanding energy efficiency budgets, emboldened by the belief in significant missed opportunities for cost-effective investments. This commitment has led to policies such as the “loading order” of California,[42] in which cost-effective energy efficiency is the priority resource among all resources, and to the energy efficiency performance standards in Connecticut.

Administration

In several jurisdictions, the regulator or the legislature has opted to delegate administration of energy efficiency programs to a central agency or private sector business. These jurisdictions include Oregon, Wisconsin, Ohio, New York, New Jersey, Washington DC, Vermont, and Maine. Connecticut created a body to review and approve the programs that are implemented by the utilities.

Advantages of this approach are several.

- A primary motivation for this choice is to take the utilities out of the position of promoting reduced sales through energy efficiency, while at the same dealing with a financial structure that improves with every sale and declines with every lost sale.

- Other advantages include a coherent rationale and identity for energy efficiency programs throughout the jurisdiction. This helps to unify advertising of programs in the media, and also unifies media coverage (making success more important). Consumers learn to expect one consistent level of service quality, which is helpful for businesses with several locations throughout the jurisdiction in different utility service areas.

- Regulators have to focus on the performance of just one entity, reducing the number of dockets in which energy efficiency performance and corollary cost recovery are issues. Costs are also saved in administration and in evaluation, monitoring and verification.

There are disadvantages with the central administration, though all have solutions.

- The utility knows its customers and its service territory – keeping the customer contact with the utility promotes customer satisfaction with the utility and also makes it easier the utility to target efficiency to address system load growth and to integrate with resource planning. Further, in some jurisdictions, the central agency has been unable to obtain customer information valuable to deliver superior customer service. Regulators can address these coordination issues by making it clear that the central agency and the utility are equals in using and protecting customer information from inappropriate use. With full information in hand, the central agency and the utility can work as partners to serve customer and system needs.

- On the other hand, the central agency may become isolated from customers, especially if contractors are extensively used. The central agency can make it a priority to maintain a customer focus. An advisory committee can also serve to assure that real customers and their needs remain in clear focus for the central agency.

- Some utilities find that energy efficiency is consistent with core values and resent the lack of confidence represented by having the responsibility taken away, and their customers lose the

[42] This is discussed in more detail in Appendix A under California DSM Summary.

chance to be served by a truly committed utility. The jurisdiction can provide a process that allows such a utility to petition to provide service to its customers that is equal or superior to service from the central agency. This is allowed in Vermont; two utilities, Burlington Electric Department and Washington Electric Cooperative, deliver programs.

- Since government has a hand in centralizing the money collected for energy efficiency, appropriators have been tempted to siphon the money for general government purposes, essentially creating a hidden tax on electric consumers. Vermont's statute addresses this concern.[43]

- In cases where utilities in a jurisdiction have dramatically different avoided costs, there could be a concern about imposing a statewide cost benefit test to apply to extremely different circumstances. On the other hand, with wholesale market competition becoming increasingly settled in practice, and a consistent set of incremental supply options available, avoided costs, while at least as difficult to forecast as ever, are far more consistent across a group of proximate utilities than average costs based on legacy decisions are likely to be. Jurisdictions such as Vermont and California are pursuing a practice of a statewide minimum energy efficiency effort (California via utilities, Vermont via a third party statewide entity) overlaid with a utility-specific commitment to energy efficiency based on each utility's specific circumstances.

- Finally, the targeting and implementation of DSM programs and their evaluation may require data and information that have been collected by utilities over the years, e.g., consumption data. In some cases, the cooperation between the central DSM delivery agency and the utility has been less than satisfactory with claims of proprietary customer data inhibiting program implementation and evaluation.

The debate over the administration and evaluation of DSM efforts has been intense in a number of states.[44] Vermont was the first state to truly centralize DSM delivery. California has tried a number of approaches, with the current approach being the delivery of DSM by that state's utilities, but the impact evaluation of the programs is conducted by the CPUC (process evaluations can be conducted by the utilities). The debate over the appropriate administration of programs, particularly where there are a number of utilities in a jurisdiction, has been controversial – most utilities oppose the use of a central

---

[43] The full text of Vermont statute, 30 VSA section 209 (d) (3) with the relevant part bolded: In addition to its existing authority, the board may establish by order or rule a volumetric charge to customers for the support of energy efficiency programs that meet the requirements of section 218c of this title. The charge shall be known as the energy efficiency charge, shall be shown separately on each customer's bill, and shall be paid to a fund administrator appointed by the board. When such a charge is shown, notice as to how to obtain information about energy efficiency programs approved under this section shall be provided in a manner directed by the board. This notice shall include, at a minimum, a toll free telephone number, and to the extent feasible shall be on the customer's bill and near the energy efficiency charge. **Balances in the fund shall be ratepayer funds, shall be used to support the activities authorized in this subdivision, and shall be carried forward and remain in the fund at the end of each fiscal year. These monies shall not be available to meet the general obligations of the state.** Interest earned shall remain in the fund. The board will annually provide the legislature with a report detailing the revenues collected and the expenditures made for energy efficiency programs under this section.

[44] The discussion relating to the creation of the Office of Clean Energy within the New Jersey Board of Public Utilities (BPU) addresses many of these issues. The history of the Office of Clean Energy can be found on the BPU website: http://www.bpu.state.nj.us/cleanEnergy/CEPHistory.shtml and in a report on administration of energy efficiency programs. The report, commissioned by the BPU to assess alternative central and utility administrative options, is called "Recommendation on the Administration of Energy Efficiency and Renewable Energy;" for New Jersey Board of Public Utilities; Docket No EX01070447; Davies Associates Incorporated; April 2002. This is located on the BPU website at: http://www.bpu.state.nj.us/reports/davies/davies.pdf.

government agency to interact with customers on items that might impact that utility's relationship with a customer. In general, utilities still deliver DSM programs in most states, but a few leading states have set up central entities to deliver SBC funded programs (e.g., New York, New Jersey, and Wisconsin). Even in these states, exceptions have been made for certain types of programs and customer segments.

Stakeholders

Successful energy efficiency program administrators generally have access to a stakeholder process that provides useful insights into what is working and what needs fixing. It is important that the program administrator takes the approach that program changes are likely, given changes in penetration, changes in the economy and political environment, opportunities that emerge with specific prominent customers, and changes in the technology and services that can be offered to customers. Sometimes, this process is a formal collaborative one with long-standing members, supervised by the regulator, which may or may not have standing to make formal proposals to change programs. Stakeholders could also be organized into an advisory board. Occasional customer forums go further to assure programs are meeting community needs.

Annual reports are useful to demonstrate, in a transparent way, recent activities, including success stories and measuring success against goals, as well as to reinforce principles for why these programs exist in the first place.

Demand Response – Another Flavor of Consumer Electric Resources

It is becoming a bromide that a wholesale electric market cannot be considered fully working unless there is a sufficiently active demand side. What does this mean? In places that are developing demand response programs, they focus in two essential functions: as a peaking resource that contributes to resource adequacy such that more generation is not needed; or, as a resource prepared to be injected into the market at any time, not necessarily in a reliability situation, to control volatile prices.

A fundamental issue regarding demand response that remains under development is how to package the offering to the customer so that it is profitable and convenient to participate. The customer may have to add some investment to control loads, and may also require a communications link to the utility or ISO that may lack convenience or reliability. In addition, there are more utilities (see the discussion of PG&E in Section 3.1 and Appendix A) that are integrating energy efficiency and demand response offerings. For example, a lighting project may not be cost-effective on its own, but when dimming capability is added it can now participate as a DR resource and gain benefits from that set of programs. Regardless, it is more expensive to make multiple trips to a customer and a customer likes to receive all its demand-side services without having to work through separate programs and delivery organizations (one-stop shopping).

Another issue revolves around how to recognize the many values of demand response. For example, demand response can provide service equivalent to reliability reserves – is there a way to compensate customers for this value? A demonstration effort to address this is underway at ISO-New England.

Despite these growing pains, participation in demand response in ISOs like PJM is rising, and it may be that mature customer familiarity with demand response programs will take some time along with some concerted effort to educate them.

One dilemma in a place with an ISO is who should manage the demand response programs: the utility or the ISO? As the ISO is usually the reliability coordinator for the area and also usually manages the regional wholesale electricity market, there is a significant advantage to having unified programs. Under this model, the utility would "retail" the ISO programs to ultimate customers. Helping to work out disputes arising from utilities happy with their own programs is one occupation of regulators.

Efficiency through Pricing

Earlier, the issue of baselines was discussed. Another way baselines can change is by introducing a new pricing regime or a new rate design. If consumers are either allowed or mandated to take service with prices that change over the year to be higher when production costs tend to be higher, and lower when production costs tend to be lower, then they may be motivated to spend more on their own to avoid high priced usage. Some suggest that this is a powerful tool that is under-utilized, while others note that some of these systems cost a lot to implement and many consumers are unwilling or incapable of managing usage during different time periods, and would lose. New Jersey and California, for example, are experimenting with pricing pilot programs to evaluate these possibilities.

Generally, the more that rates reflect the long term societal costs of new resources, the more favorably energy efficiency will look to regulators, planners, and customers.

Issue 6: Recommendations – Other Issues

There are many facets to launching and overseeing quality energy efficiency and demand response programs. Success does nothing to diminish the appropriate level of oversight and vision needed to be effective. Some essential threads:

- Leadership is needed to push through the challenges that invariably arise and to keep the longer term in mind – a DSM program may not be immediately cost-effective and it will take time for the value of DSM to be realized. Good leadership can set appropriate expectations and timelines, as well as ensure that the effort is sustained and is one component of a multi-year plan.

- A stakeholder process encompassing trade allies, customers and other stakeholders can be valuable to gain new perspectives and support for programs.

- Demand response needs to be integrated with energy efficiency since there are complementary aspects in delivery and economies that can be gained through technologies that both save energy and provide the customer with the ability to manage their energy use such that they can participate in a DR program.

- Pricing of electricity and gas is important for the economics of energy efficiency and demand response. Time differentiated rates that recognize the varying value of the resource across hours and also better reflect the full societal cost of new resources will make DSM look more favorable to planners and customers.

5. BIBLIOGRAPHY & LINKS

General

- Economically Achievable Energy Efficiency Potential in New England (NEEP study, updated for 2005) http://www.neep.org/files/Updated_Achievable_Potential_2005.pdf
- Trends in Utility-Related Energy Efficiency Spending in the U.S. (PPP) (ACEEE presentation)
- http://www.swenergy.org/nml/index.html "SWEEP's new study examines the potential for and benefits from increasing the efficiency of electricity use in the southwest states of Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. The study models two scenarios, a "business as usual" Base Scenario and a High Efficiency Scenario that gradually increases the efficiency of electricity use in homes and workplaces during 2003-2020."http://www.mass.gov/doer/pub_info/ee02-long.pdf
- International Measurement and Verification Protocol www.ipmvp.org
- Responding to the Natural Gas Crisis: America's Best Natural Gas Energy Efficiency Programs http://www.aceee.org/utility/ngbestprac/u035.pdf
  Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies http://aceee.org/pubs/e032full.pdf
- Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets: Updated and Expanded Analysis http://aceee.org/pubs/e052full.pdf

Selected RAP Publications

- Electric Energy Efficiency and Renewable Energy in New England: An Assessment of Existing Policies and Prospects for the Future
- Surveying DSM Programs Nationwide: Is There Money on the Table? (PPP)
- Beyond the SBC: New Ways to Finance Efficiency (PPP)
- Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost and Efficient Electricity Service to All Retail Customers, Synapse
- Who Should Deliver Ratepayer Funded Energy Efficiency? A Survey and Discussion Paper
- Energy Efficiency Administration: Statutes and Regulatory Actions in the U.S.
- Barriers to Energy Efficiency (PPP) RAP's IRP manual, including cost-benefit test definitions and examples.

British Columbia

- Strategic Considerations for a New British Columbia Energy Policy: Final Report of the Task Force on Energy Policy, March 15, 2002. http://www.gov.bc.ca/empr/down/task_force_final_report.pdf
- British Columbia Utilities Commission, Resource Planning Guidelines, Dec. 2003. http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf
- Energy for Our Future: A Plan for BC, 2002.

- Order in Council No. 1123 Special Direction HC2. http://www.bchydro.com/reg_files/heritage/order_in_council_no_1123_sd_hc2.pdf
- Resource Expenditure and Acquisition Plan (the REAP), March 2005. http://www.bchydro.com/rx_files/info/info10201.pdf
- Conservation Potential Review – 2003 - http://www.bchydro.com/rx_files/info/info10236.pdf
- BC Hydro 2004 Integrated Electricity Plan http://www.bchydro.com/info/epi/epi19230.html
- Fortis BC Semi-annual Demand Side Management (DSM) report http://www.bcuc.com/Documents/Proceedings/2005/DOC_7149_B-23%20DSM%20-BCUC%20IR%20111.pdf
- Fortis 2005 Revenue requirements submission http://www.bcuc.com/Documents/Proceedings/2004/DOC_5708_B-1%20FortisBC%202005%20Revenue%20Requirements.pdf
- TGI 2005 Revenue requirements submission http://www.bcuc.com/Documents/Proceedings/2005/DOC_8981_B-3_Advance%20Info%202005%20Annual%20Review.pdf

California

There have been many studies done in CA, analyzing CA EE programs in any number of ways. Studies available at http://www.calmac.org/search.asp (California Measurement Advisory Council website). Especially useful:

  - The California Evaluation Framework http://www.calmac.org/publications/California_Evaluation_Framework_June_2004.pdf Explains (in 500 pages) CA's "consistent, systemized, cyclic" approach to planning and evaluation of EE. Includes a bibliography of literature on EE evaluation protocol that the new Framework is based on.
  - California's Secret Energy Surplus: The Potential for Energy Efficiency http://www.ef.org/documents/Secret_Surplus.pdf
  - 2003 Proposed Energy Savings Goals (CEC): http://www.energy.ca.gov/reports/2003-11-05_100-03-021F.PDF

- The Energy Action Plan http://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm
- S. Bender, M. Messenger and C. Rogers. July, 2005. "Funding and Savings for Energy Efficiency Programs for Program Years 2000 through 2004." California Energy Commission. http://www.energy.ca.gov/2005_energypolicy/documents/2005-07-11_workshop/presentations/2005-07-11_FUNDING+SAVINGS.PDF
- F. Coito and M. Rufo. September, 2002. "California's Secret Energy Surplus: The Potential for Energy Efficiency." Prepared by Xenergy for Energy Foundation. http://www.ef.org/documents/Secret_Surplus.pdf

Selected CPUC Decisions:

  - **D0312060 --** December 18, 2003 - http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/32828.htm

- **D-0409060** – September 23, 2004 http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212-02.htm#P123_13438
- **D0501055** – January 27, 2005- http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43628.htm
- **D0504051** – April 21, 2005 http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/45783.htm#P75_2023
- **D0509043** – September 22, 2005 http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm

Connecticut

- Annual reports to Connecticut's legislature re: energy efficiency and load management costs, savings, benefits. http://www.dpuc.state.ct.us/Electric.nsf/By%20ECMB%5C4.%20Reports?OpenView&Start=1&Count=30&Expand=1#1
- The Energy Independence Act (Public Act 05-1) http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm
- Public Act 98-28 (restructuring legislation that established the C&LM fund) http://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm

Relevant dockets:

Active and inactive docket documents can be accessed at: http://www.state.ct.us/dpuc/database.htm

- Docket 04-10-02: Gas utility conservation plans.
- Docket 04-11-01: Included a C&LM-funded pilot supplemental price response program to be implemented in 2005 for certain high price events (see pp 20-21).
- Docket 05-07-14: In Phase I, the DPUC will identify short-term strategies to mitigate capacity-related and congestion-related charges ("federally-mandated congestion charges" or FMCC), including load response, conservation, distributed resources and other measures. Phase 2 will examine intermediate-term approaches to mitigate FMCC. Both supply and demand approaches will be allowed to compete.
- Docket 05-07-19: Examines the use of conservation and other DSM strategies as Class III resources to meet certain supply goals.
- Docket 05-09-09: Examining possible decoupling strategies for both gas and electric. utilities. Rate design options to support energy policy goals may also be considered.
- Docket 05-10-02: The 2006 C&LM plans filed jointly by the two major electric utilities (CL&P and UI).

- The Energy Conservation Management Board (ECMB) reports on program results to the legislature every spring. The "Report of the ECMB: Year 2004 Programs and Operations" can be seen at http://www.dpuc.state.ct.us/Electric.nsf/cafda428495eb61485256e97005e054b/834bce27d18f256a85256ff80051f63d?OpenDocument

- Other ECMB information can be accessed at: http://www.state.ct.us/dpuc/ecmb/

Illinois

- Phone call with Howard Learner, Environmental Law and Policy Center, October 2005.
- Phone call with Michelle Mishoe, Illinois Commerce Commission, October 2005.
- Phone call with Charles Budd, ComEd, October 2005.
- Illinois Commerce Commission web site: www.icc.Illinois.gov, "Sustainable Energy Plan".
- Office of the Governor, Press Release, February 14, 2005.
- Illinois Commerce Commission, "Illinois Sustainable Energy Initiative, ICC Staff Report" (Illinois Commerce Commission, Springfield, IL, 2005)
- www.illinoiscleanenergy.org.
- Letter from Frank Clark of ComEd to ICC Chairman Ed Hurley, September 6, 2005, posted on the ICC web site, www.icc.illinois.gov, Sustainable Energy Plan.

Iowa

- Statutory requirements can be found in Iowa Code 476.6(17), online at http://www.legis.state.ia.us/IACODE/2003/476/6.html.
- Regulatory rules can be found in Chapter 35 of the Iowa Administrative Code, online at http://www.legis.state.ia.us/Rules/Current/iac/199iac/19935/19935.pdf
- Iowa Utility Board Energy Efficiency Team. September 2005. Energy Efficiency in Iowa: Investor-owned Utility (IOU) Results. Power Point Presentation, available online at http://www.state.ia.us/government/com/util/ee.html
- Iowa Utilities Board Staff Energy Efficiency Team. 2005. "Energy Efficiency in Iowa: Investor-owned Utility (IOU) Results." Power Point Presentation, Iowa Utilities Board. http://www.state.ia.us/government/com/util/ee.html (accessed November 10, 2005)

Massachusetts

- RLW Analytics, Inc. and Shel Feldman Management Consulting. June, 2001. "The Remaining Electric Energy Efficiency Opportunities in Massachusetts: Final Report." http://www.mass.gov/doer/pub_info/e3o.pdf
- Chapter 140 of the Acts of 2005 at http://www.mass.gov/legis/laws/seslaw05/sl050140.htm
- Final Order at http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm
- Chapter 25, Section 19 of the General Laws of Massachusetts
- Docket 04-11 at: http://www.mass.gov/dte/electric/04-11/819order.pdf
- Massachusetts Division of Energy Resources. 2004. "2002 Energy Efficiency Activities." http://www.mass.gov/doer/pub_info/ee02-long.pdf
- Massachusetts Electric Company and Nantucket Electric Company (aka NGrid). April 2005. "2005 Energy Efficiency Plan." May be obtained from NGrid.

- Massachusetts Electric Company and Nantucket Electric Company (aka NGrid). 2004 “Energy Efficiency Annual Report.” May be obtained from NGrid.
- DTE Order 98-100 re: cost-effectiveness http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm
- The 1997 Restructuring Act www.mass.gov/legis/laws/seslaw97/sl970164.htm.
- The results of the 2002 Act can be seen at http://www.mass.gov/legis/laws/mgl/25-19.htm.

Minnesota

- Minnesota statute 216B.241.
- Personal conversation with Bridget McLaughlin, Regulatory Analyst for Xcel Energy, October 2005.
- Xcel Energy, “2005/2006 Biennial Plan, Minnesota Natural Gas and Electric Conservation Improvement Program” p. xx (Xcel Energy, Minneapolis, MN, June 2004).
- Xcel Energy, “2004 Status Report & Associated Compliance Filings, Minnesota Natural Gas and Electric Conservation Improvement Program” p. 5 (Xcel Energy, Minneapolis, MN, April 2005).
- ACEEE, “America’s Best: Profiles of America’s Leading Energy Efficiency Programs” (ACEEE, Washington, DC, March 2003). Available at www.aceee.org.
- Chris Davis, MDOC, personal conversation, October 2005.
- California Energy Commission, “California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects” (California Energy Commission, Sacramento, CA, October 2001).
- Xcel Energy’s Biennial CIPwww.xcelenergy.com, Filing (Docket # 04-820, filed 6/1/04) and CIP Status report (Docket 02-854.19, filed 4/1/05) are available online on part of the MDOC’s web site: edockets.state.mn.us.
- Xcel Energy’s 2004 Resource Plan is available on their web site [www.xcelenergy.com, “About Energy and Rates, Resource Plan (MN)”]

New Jersey

- SB7 Electric Discount and Energy Competition Act February 1999 (The Act) www.bpu.state.nj.us/wwwroot/energy/EX00020091ORD.pdf
- Energy and Economic Assessment of Statewide Energy-Efficiency Programs, New Jersey Clean Energy Collaborative, July 9, 2001
- New Jersey’s Clean Energy Program: 2005 Program Descriptions and Budget, Utility Managed Energy Efficiency Programs, Updated June 8, 2005
- New Jersey’s Clean Energy Program: 2005 Program Descriptions and Budgets, Office of Clean Energy Managed Renewable Energy Programs and Administrative Activities, June 9, 2005
- New Jersey Board of Public Utilities May 6, 2005. New Jersey’s Clean Energy Program: 2004 Annual Report. http://www.njcleanenergy.com/media/OCE_AR_final_0907_4_1.pdf

- New Jersey Statewide Market Assessment, Xenergy 1999. http://www.njcleanenergy.com/html/5library/nj_baseline_studies_base.html

Relevant Board of Public Utilities (BPU) Orders

  - Docket # EO04080894: Order - In the Matter of the Adoption of New Jersey's Clean Energy Program Protocols to Measure Resource Savings, Dec. 22, 2004. http://www.bpu.state.nj.us/wwwroot/cleanEnergy/EO04080894_20041223.pdf
  - Docket # EX04040276: Order - In the Matter of Comprehensive Energy Efficiency and Renewable Energy Resource Analysis for 2005-2008, Dec. 22, 2004. http://www.bpu.state.nj.us/wwwroot/energy/EX03110946_20040428.pdf
  - Docket # EO02120955: Order - In the Matter of the New Jersey Clean Energy Program http://www.bpu.state.nj.us/home/BO_CE.shtml
  - Docket #EX03110905 et al.: Order – July 2004
  - Docket # EX03110946: Order - In the Matter of Appropriate Utility Funding Allocation for the 2004 Clean Energy Program http://www.bpu.state.nj.us/wwwroot/energy/EX03110946_20040428.pdf

- The 2004 PJM State of the Market Report, March 8, 2005. http://www.pjm.com/markets/market-monitor/som.html

- Harrington, C., and Murray C., the Regulatory Assistance Project, May 2003. Who Should Deliver Ratepayer Funded Energy Efficiency? A Survey and Discussion Paper.

<u>*New York*</u>

- Department of Public Service System Benefits Charge (SBC) http://www.dps.state.ny.us/sbc.htm

- Public Service Commission (NYSERDA), SYSTEM BENEFITS CHARGE: Revised Operating Plan for New York Energy $mart^{SM} Programs (2001-2006), *June 12, 2002.* http://www.nyserda.org/sbc2001-2006.pdf

- New York Energy $mart^{SM} Program Evaluation and Status Report: Report to the System Benefits Charge Advisory Group, Final Report, May 2005, http://www.nyserda.org/Energy_Information/05sbcreport.asp

- 2002 State Energy Plan and Final Environmental Impact Statement (Energy Plan), http://www.nyserda.org/Energy_Information/energy_state_plan.asp

- State Energy Plan - 2004 Annual Report and Activities Update, http://www.nyserda.org/Energy_Information/2004sep_annual_report.pdf

- NYSERDA, Toward a Brighter Energy Future: A Three Year Strategic Outlook, 2005-2008. http://www.nyserda.org/Energy_Information/strategicplan.pdf

- System Benefits Charge III, Staff Proposal for the Extension of the System Benefits Charge (SBC) and the SBC-Funded Public Benefit Programs, Staff Report, August 30, 2005. http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/721B232D106700BE85257069006D3DF4/$File/05m0090.08.30.05.pdf?OpenElement

- Order Continuing the System Benefits Charge (SBC) and The SBC-Funded Public Benefit Programs, December 14, 2005 http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/5375707FAF2225B2852570D600700767/$File/05m0090_12_21_05.pdf?OpenElement

Ontario

- OEB Report: Demand side management and Demand Response in the Ontario Electricity Sector, March 1, 2004. http://www.oeb.gov.on.ca/documents/cases/RP-2003-0144/pressrelease_report_finalwithappendices_030304.pdf
- Electricity Demand in Ontario – Assessing the Conservation and Demand Management (CDM) Potential, ICF Consulting, November 2005.
- Minister's Directive to the OEB. http://www.oeb.gov.on.ca/documents/directive_dsm_070703.pdf.
- Electricity Conservation & Supply Force Task Report, January 2004.
- http://www.energy.gov.on.ca/english/pdf/electricity/TaskForceReport.pdf
- OEB Information Bulletins and Procedural Orders.
    - http://www.oeb.gov.on.ca/documents/dcdm_informationbulletin_310804.pdf
    - http://www.oeb.gov.on.ca/documents/dcdm_po_051004.pdf
    - http://www.oeb.gov.on.ca/documents/dcdm_amend_proc_order2_041104.pdf
- Bill 100, Dec. 9, 2004. http://www.ontla.on.ca/documents/Bills/38_Parliament/Session1/b100_e.htm
- Bill 21, introduced Nov. 3, 2005, http://www.ontla.on.ca/documents/Bills/38_Parliament/session2/b021_e.htm
- Conservation Action Team Report http://www.energy.gov.on.ca/english/pdf/conservation/CAT_Report.pdf
- Report of the OEB on EDR 2006 http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_EDR.htm
- TRC Guidelines http://www.oeb.gov.on.ca/documents/cdm_trcguide_141005.pdf

Oregon

- The Energy Trust of Oregon 2005-2006 Final Action Plan http://www.energytrust.org/Pages/about/library/plans/0506_action_plan.pdf
- Energy Efficiency Approved 2005 Budget http://www.energytrust.org/Pages/about/library/financial/05_Budget/EE.pdf
- ECONorthwest. March, 2005. "Report to Legislative Assembly on Public Purpose Expenditures: Final Report." http://www.puc.state.or.us/erestruc/public_purpose_report_030305.pdf
- H. Haeri, L. Miller and M. Perussi. January, 2004. "Assessment of Demand Response Resource Potentials for PGE and Pacific Power." http://www.nwcouncil.org/energy/dr/library/dr_assessment.pdf

- OPUC Order on demand response, opening investigation http://apps.puc.state.or.us/orders/2003ords/03%2D408.pdf
- OPUC Staff report. May 2003. “Demand Response Programs for Oregon Utilities.” http://www.puc.state.or.us/elecnat/demand/default.htm
- LBNL. August 2005. “Real Time Pricing as a Default or Optional Service for C&I Customers: A Comparative Analysis of Eight Case Studies.” LBNL Report No. 57661. http://drrc.lbl.gov/drrc-pubs2abs.html
- Re: State of Oregon Energy Programs: http://oregon.gov/ENERGY/programs.shtml
- H. Haeri, L. Miller and M. Perussi. January, 2004. “Assessment of Demand Response Resource Potentials for PGE and Pacific Power.” http://www.nwcouncil.org/energy/dr/library/dr_assessment.pdf
- OPUC Staff report. May 2003. “Demand Response Programs for Oregon Utilities.” http://www.puc.state.or.us/elecnat/demand/default.htm

Texas

Documents on this topic for all distribution utilities in Texas can be accessed using the PUCT Interchange page at

http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/login/pgLogin.asp.

- Click on “log in.”
- Enter control #30739, then search, to access efficiency reports and plans.
- Enter control #26310, then search, to view reports to the TCEQ on emissions reductions due to efficiency programs.

Present program offerings for all Texas distribution utilities can be seen at

http://www.texasefficiency.com/

See also the PUCT's January 2005 "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas" at: http://www.puc.state.tx.us/electric/reports/scope/index.cfm

Discussion of efficiency programs begins on page 67 of that report.

Rules can be viewed at the PUCT website

http://www.puc.state.tx.us/rules/subrules/electric/index.cfm

The most relevant rules are:

- Rule 25.181 covers most of the substance of the program approach, including goal-setting, planning, administration, cost-effectiveness, cost recovery, M&V guidelines, detailed reporting requirements, etc.

- Rule 25.183 outlines general reporting requirements, including PUCT report to TCEQ re: emissions.

- Rule 25.184 includes links to templates for all the approved SOP and MT approaches, as well as deemed savings values, and stipulated values.

Vermont

- Act 61 of the 2005 Legislature established the SPEED program. Text can be found at: http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT061.HTM
- 30 VSA 209 (d) and (e) http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00209
- Docket 6290, establishing the DUP process, can be found at http://www.state.vt.us/psb/orders/2003/files/6290irpextord.pdf
- ACEEE's Special Case Study of VGS' comprehensive programs can be found at: http://aceee.org/utility/ngbestprac/vgsprtflio.pdf
- See ACEEE's study of Exemplary Natural Gas Efficiency Programs at http://www.aceee.org/utility/ngbestprac/ngbestpractoc.pdf
- A. Bishop. 2004. "Efficiency Vermont: Vermont's Energy Efficiency Utility". Power Point Presentation, Vermont Public Utilities Board. Available by request; email abishop@psb.state.vt.us
- Vermont Department of Public Service. 1997. "The Power to Save: A Plan to Transform Vermont's Energy Efficiency Markets." http://publicservice.vermont.gov/energyefficiency/ee_files/efficiency/power_to_save.pdf
- Vermont Energy Investment Corporation, Inc. June 2005. "Response To Request For Proposals For a Vermont Energy Efficiency Utility." http://www.state.vt.us/psb/vol1eeuprop.pdf
- Vermont Department of Public Service. May 2002. "Report and Recommendations to the Vermont Public Service Board Relating to Vermont's Energy Efficiency Utility."
- Efficiency Vermont: 2004 Preliminary Report. http://www.efficiencyvermont.com/index.cfm?L1=292&L2=535&sub=bus
- Efficiency Vermont: 2003 Annual Report. http://www.efficiencyvermont.com/Docs/2003ExecutiveSummary.pdf

Washington

- For more information on PSE's programs, refer to their website at: http://www.pse.com/yourhome/rebates/index.html and http://www.pse.com/yourbusiness/grants/grants.html
- 2004 DSM Reports for PSE, Pacificorp, and Avista
- PSE's 2005 Least Cost Plan, available for download online at https://www.pse.com/about/supply/resourceplanning.html
- Pacificorp's 2004 Least Cost Plan, available at http://www.pacificpower.net/Navigation/Navigation36807.html

Wisconsin

- Wisconsin Legislative Council Staff, "New Law on Electric Utility Regulation—the "Reliability 2000" Legislation, Part of 1999 Wisconsin Act 9 (the 1999-2001Biennial Budget Act), Information Memorandum 99-6"(Wisconsin Legislative Council Staff, Madison, WI, December 2, 1999).
- Wisconsin Department of Administration, Division of Energy, "Wisconsin Public Benefits Program: 2005 Annual Report", p. 3 (Wisconsin Department of Administration, Madison, WI, 2005).
- Telephone conversation, Kathy Kuntz, WECC's Director of Operations, November 2005.
- State of Wisconsin, "Report of the Governor's Task Force on Energy Efficiency and Renewables", p.5 (Wisconsin Department of Administration, Madison, WI, October 2004).
- Telephone seminar presentation by WECC's Kathy Kuntz on September 28, 2005.
- Telephone seminar presentation by WECC's Ed Carroll on September 28, 2005.
- Wisconsin Department of Administration, Division of Energy, "Focus on Energy Statewide Evaluation: Initial Benefit-Cost Analysis" (Wisconsin Department of Administration, Madison, WI, March 31, 2003).
- Information on the Wisconsin Focus on Energy Programs and reports is available at www.focusonenergy.com.
- The Wisconsin Legislative Council staff's report on the Reliability 2000 legislation is available on the internet at: www.legis.state.wi.us/lc/3_COMMITTEES/JLC/Prior%20Years/jlc99/pubs/im99_6.pdf
- Report from the Wisconsin Governor's Task Force on Energy Efficiency and Renewable is available at http://energytaskforce.wi.gov/.