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May 30, 2003

British Columbia Utilities Commission
6th Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sirs:

Re: Terasen Gas Inc. (formerly BC Gas Utility Ltd.)
Multi-Year Performance Based Rate Plan for 2004 – 2008
Response to BCUC Staff and Intervenors Information Requests

As per Commission Order G-38-03, Terasen Gas respectfully submits responses to information requests received from BCUC Staff and the following Intervenors:

- BCOAPO et al.
- Direct Energy Marketing Limited
- Elk Valley Coal Corporation (Nos. 1 and 2)
- Lower Mainland Large Gas Users Association et al.

Should additional copies of the responses be required, please contact Regulatory Services, Terasen Gas Inc. at (604) 592-7461.

Yours very truly,

TERASEN GAS INC.

Original signed by

Scott Thomson

Encl.

c. Registered Intervenors

MULTI-YEAR PERFORMANCE BASED RATE PLAN FOR 2004 – 2008

RESPONSE TO BCUC AND INTERVENORS INFORMATION REQUESTS

VOLUME 2

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1.0 Application, Tab C

1.1 Reference: C-24

How did Terasen Gas determine that a PIF of 0.75 percent was appropriate?

Response

The adjustment factor of 0.75% was determined by developing a formula approach to setting controllable costs relative to CPI that would yield lower revenue requirements than would arise from traditional cost of service regulation while not adversely affecting the Company's risk profile. Terasen Gas believes that 0.75% is a reasonable factor in view of the low base rates determined through the 2003 Revenue Requirement proceeding, the current and projected low inflation rate environment, and the reduced opportunity for large one-time efficiencies available to the Company.

It should also be noted that CPI is a measure of general price increases in the economy. Prices are affected by changes in the costs of labour and materials required to provide goods and services and by the changes in the productivity of the industries and distribution channels that are involved in the manufacture and distribution of the goods and services. CPI is a measure of prices and those prices incorporate economy-wide productivity. A price setting formula that uses CPI as part of the formula contains in it a productivity factor equal to the economy-wide productivity. The proposed formula provides further efficiencies beyond those reflected in the economy-wide measure of CPI with the inclusion of the 0.75% adjustment factor.

1.2 *If the 50:50 sharing mechanism were set to 0 percent, what increase in PIF would be appropriate? Why*?

Response

The adjustment factor in effect provides "up front" sharing to customers. Therefore, lower sharing would directionally support using a somewhat higher adjustment factor. However, it is not possible to establish a direct relationship between the adjustment factor and the sharing mechanism in isolation of the all of the other factors incorporated in the PBR. The sharing mechanism provides for the sharing of both positive and variances from the formula. Setting the sharing mechanism to zero would result in the Company being at risk for the full amount of all variances from the formula based rates. While the Company will seek to maximize all efficiency gains during the term of the PBR, it is uncertain at this time what other factors may arise that may cause variances from the formula. Implementing a higher adjustment factor would expose the Company to increased risk.

As a design feature, the 50:50 sharing mechanism ensures alignment of customer and Company interests and provides a more visible sharing of benefits than would be provided through the adjustment factor. Terasen Gas believes that the 0.75% and the 50:50 sharing mechanism provide an appropriate balance between customers and the Company while providing incentives for the Company to undertake initiatives to achieve efficiencies.

1.3 Reference: C-14

Terasen Gas plans to attract added load by targeting increased gas usage for cooking, clothes drying and water heating. Please show the relative efficiencies and efficiency adjusted customer costs for these appliances.

Response

The table below outlines Terasen Gas' best estimates at this time of the relative efficiencies and adjusted customer costs for the appliances requested. Terasen Gas plans to conduct additional research which will assist in validating consumption levels by end use.

End Use[2]	Operating Characteristic	Gas	Electric
Cooking (range)	Energy efficiency[1]	N/A	N/A
	Average consumption / year	780 kWh - 1,667 kWh (3 Gj - 6 Gj)	780 kWh
	Estimated operating cost / year[3]	$33 - $66	$45
Clothes drying	Energy efficiency	2.67 lbs / kwh min EF	3.01 lbs / kwh min EF
	Average consumption / year	1,029 kWh (4 Gj)	1,042 kWh
	Estimated operating cost / year	$44	$60
Water heating	Energy efficiency	0.55 to 0.62	0.86 to 0.89
	Average consumption / year	7,500 kWh - 8,333 kWh (27 Gj - 30 Gj)	5,149 kWh - 5,407 kWh
	Estimated operating cost / year	$299 - $332	$297 - $312

Notes:

1) Standardized industry efficiency rating standards do not exist for ranges.
2) Information sources include Terasen Gas estimates and BC Hydro.
3) Based on current BC Hydro ($0.0577 per kWh) and Terasen Gas Lower Mainland ($11.056 per Gj) rates as of May 27, 2003. Basic monthly charges excluded.

At the Workshop Terasen Gas indicated that this targeted increased gas usage would be funded by the proposed DSM grants. Why wouldn't these load building grants be recorded in deferral accounts that were separate from the DSM energy efficiency incentives?

Response

The reference at the workshop was about applying a similar concept or model to the load building initiatives as that used for DSM programs over the past number of years. A separate deferral account would be used. It was not intended that the DSM and load building initiatives be commingled.

1.4 Reference: C-11

Please show the levels of bad debt expense and late payment charges for the past five years.

Response

The bad debt expense and late payments charges for the past five years are as follows:

	1998	1999	2000	2001	2002
Bad Debt					
Interior	$ 891	$ 1,524	$ 1,269	$ 3,312	$ 2,641
Lower Mainland	1,400	1,444	1,864	2,785	4,550
Total	$ 2,291	$ 2,968	$ 3,133	$ 6,097	$ 7,191

	1998	1999	2000	2001	2002
Late Payment Charges					
Total	$ 787	$ 1,050	$ 1,332	$ 1,798	$ 1,976

1.5 Reference: C-12 and C-16

The BCUC Panel has identified a concern that flowthrough expenses and exogenous factors may drive up delivery margins. Please identify all flowthrough items and exogenous factors and provide a discussion of the merits of each for continued flowthrough as opposed to fixing an expense and allowing the item to be "at risk".

Response

The following table provides a listing of the flow-through items and exogenous factors together with a discussion of the merits of each for continued flow-through as opposed to fixing an expense and allowing the item to be "at risk".

In general terms, flow-through and deferral treatment is sought for these items for the following reasons:

- the factors affecting these items are largely from outside events;
- there is limited ability for the Company to influence these costs;
- for some items there is significant volatility or unpredictability leading potentially to either windfall gains or losses; and
- the requested treatment for these items seeks to maintain a similar risk profile for the Company.

The degree to which each of the proposed flow-through items can be influenced by the Company will vary. Some items which may have some of the characteristics described above and which therefore lend themselves to classification as exogenous factors, could be considered “partially controllable” in that the Company may be able to take some actions to reduce exposure to these costs. However, there remains significant risk due to the volatility of the costs and the degree to which outside factors determine the costs borne by the Company which would make their inclusion in the PBR formula impossible without increasing the Company’s risk profile.

The issue of partially controllable costs has been raised by some stakeholders at various points in the recent past. Questions have been posed about whether asymmetric incentives could be developed that better align the interests of customers and the Company in managing these items without adversely affecting the Company’s risk profile. There is some appeal to these suggestions from the Company’s perspective since any sharing of cost savings on these items could be used to offset costs incurred in seeking to reduce the partially controllable costs without exposing the Company to risks of further costs if these costs increase despite the Company’s best efforts.

Establishing incentives either through asymmetric incentives or through inclusion in the PBR formula will align customer and Company interests relating to reducing partially controllable costs. Terasen Gas believes that the merits of including incentives for partially controllable costs will have to be evaluated on an item by item basis and considered in the context of the overall PBR as determined through the NSP.

Cost of Service Item	Discussion
O&M Expenses Insurance costs and pension costs	Deferral treatment is sought for variances from the amount implicit in the O&M formula. Volatility in insurance and pension costs has increased significantly in the last several years for factors that are largely beyond the Company's control. During the hearing in November 2002 there were suggestions in the questioning by Intervenors that they wanted pensions costs given deferral account treatment. Deferral account treatment on these items was part of the Terasen Gas (Vancouver Island) revenue requirement settlement.
Property taxes	The Company has limited ability to influence property taxes which are imposed by municipalities and other levels of government.
1% in Lieu	A significant portion of property taxes is tied to the amount of revenues collected within municipalities (referred to as the "1% in lieu" tax). This moves up and down with commodity-related rate changes.
General, School and Other	These taxes involve a combination of assessed values and mill rates. A possible alternative to annual forecasts of property taxes would be to use a formula-based approach for rate setting with variances from the formula being deferred and amortized over three years. The three-year amortization would have a rate smoothing effect. Several stakeholders have suggested that property taxes may be in the category of "partially controllable" costs and might be suitable for a positive incentive. An incentive mechanism might assist in keeping the property tax increases and deferred amounts at lower levels.
Income taxes Tax rates	Known tax rate changes will be reflected in the rate calculations at the Annual Review each year. Tax rate changes that are not known in time to be reflected in rates will be deferred and recovered or refunded in future periods. Tax rate changes are outside the Company's control so the proposed flow-through / deferral treatment is consistent with the Company's risk profile and with past regulatory practice.

New taxes and levies	New taxes and levies result from changing government policies and legislation and are outside the Company's control. The proposed flow-through / deferral treatment is consistent with the Company's risk profile and with past regulatory practice.
Amortization Amortization of Deferred Charges	Deferred charges and related amortization expense may arise from exogenous factors during the term of the PBR. Since the exogenous factors are largely beyond the control of the Company the related deferrals would also be. A number of existing deferral accounts are for one-time occurrences in the past and will be fully amortized at varying points in the five-year period. The benefit of lower amortization expense as these expire will not be passed on to customers if the amortization of deferred charges was to be included in the formula
Leases Coastal Facilities Lease	The Company has indicated that it will file a separate application seeking to have the Coastal Facilities transferred from the current synthetic lease treatment to normal rate base treatment. This issue was reviewed in the November 2002 Hearing and is linked to an accounting standards change that will be effective January 1, 2004. The accounting standards change has been triggered by events that are beyond the Company's control.
Rate Base Return Debt Interest	Debt interest rates are affected by government policy and capital market conditions which are beyond the Company's control. The proposed flow-through / deferral treatment of debt interest is consistent with the Company's risk profile.
Return on Equity	The annual changes in the BCUC generic ROE formula will be passed through each year. This is also consistent with the Company's risk profile and with past regulatory practice.

Other Judicial, legislative or administrative changes, orders and directions Catastrophic Events Bypass GAAP changes BCUC Orders, e.g. unbundling and rate design	The listing of other exogenous items pertains to changes imposed on Terasen Gas by outside events or authorities over which the Company has little or no control. Having to absorb items of this nature would amount to moving beyond the Company's risk profile.

1.6 Reference: C-17

The Commission has received numerous complaints regarding estimated bills. Should SQI#6 be expanded to measure the average number of months that customers receive estimated bills?

Response

Terasen Gas does not believe SQI #6 should be expanded to include the number of months that customers receive estimated bills. Bi-monthly reading for the majority of customers is a significant cost saving to customers.

The current business practice is to read all small volume meters bi-monthly subject to specific end use conditions and a determination of the likely accuracy of an estimate based on historical consumption. If specific conditions are met the meter will require monthly reading until the condition is resolved or the accuracy factor is within a predetermined tolerance. The instances where estimates occur over consecutive billing periods are primarily due to customer initiated non-access, such as dogs or locked gates rather than by the meter reading provider missing the read.

1.7 Reference: C-A-1, p. 5

Is Terasen Gas able to quantify the cost of improving SQIs when it states: "BC Gas questions whether customers are willing to pay for additional improvements in the indicators"?

Response

No specific quantification of the costs necessary to improve the current level of performance against the proposed SQIs is available at this time. Each SQI would have to be evaluated separately to determine incremental improvement opportunities and their related incremental costs.

One area that has been considered relates to reducing emergency response time. This is a labour intensive activity. Terasen Gas could reduce the emergency response time by hiring and training additional emergency response resources and establishing new musters throughout the province.

The Company already has one of the best average emergency response times for Canadian natural gas distribution utilities, which is outstanding considering the geographic coverage of Terasen Gas' operations.

The question is how much more is the average customer willing to pay for a further reduction in response time? Or alternatively how much are customers willing to have the response time increase in order to reduce some cost? Trade offs have to be made and clearly there is an element of judgement required. However, Terasen Gas has been through extensive reviews of its costs and performance over the last several years, and based on those reviews believes that the current response times and the current costs are reasonable and in alignment.

1.8 Reference: C-A-1, p. 12

Should a Customer Satisfaction Survey be maintained as an SQI?

Response

No, the Company believes that Customer Satisfaction surveys are not a suitable performance measure for use as SQIs as they are more a qualitative measure than an objective quantifiable measure.

It has been the Company's experience with customer satisfaction surveys that they can be highly impacted by factors such as commodity price increases. However a number of Service Quality Indicators that are customer service focused have been included, i.e. response to emergency call, speed of answer to phone calls, billing accuracy and percent of meter exchange appointments met.

1.9 Full Term Efficiency Incentive ("FTEI")
Reference: Appendix C-A-2

1.9.1 The FTEI seems to be based on expenditures on undefined efficiencies with the costs recovered first from general revenue savings whether they are a result of the efficiency measure or not. What accountabilities exist on Terasen Gas to only pursue cost effective efficiencies?

Response

The FTEI provides a continuing incentive for the Company to pursue initiatives that provide a payback beyond the term of the PBR by allowing the Company to share in a portion of the benefits of its actions to improve controllable costs beyond the term of the PBR.

In the illustrative example of how the FTEI would operate (both in the Application at Appendix C-A-2 and during the May 15 Workshop) the Company also included the concept of recovering restructuring costs. These are two separate and distinct features of the proposal but the illustration included both in order to provide a more comprehensive example. The FTEI as proposed is meant to provide the Company with a share of the incremental benefit generated in each year of the PBR term for a full five years.

The most significant accountabilities to ensure that Terasen Gas only pursues cost effective efficiencies are (1) that there will be recovery of restructuring costs only if the Company does better than the allowed ROE under the formula; and (2) there is a sharing of benefits once the benefits exceed restructuring costs. The Company has a financial incentive to pursue those initiatives that will yield the greatest benefits at the least cost (since that will maximize its earnings) and has a further incentive not to pursue initiatives that are not cost effective since spending funds on such initiatives will reduce the Company's earnings.

The retention of benefits through the FTEI relates only to controllable cost items under the formulas relating to O&M and Capital (i.e. Net Gas-Plant-in-Service). To the extent O&M and Net Gas-Plant-in-Service are maintained below the formula levels, a portion would be retained by the Company beyond the end of the term. Some savings may be realized that were not a result of actions taken by the Company, however the opposite is also the case. Unexpected cost pressures beyond the Company's control may erode the benefits achieved on the formula based items, resulting in retention by the Company of a smaller level of benefits beyond the term of the PBR Plan.

It would be extremely difficult to track and account for each benefit or cost impact individually and therefore, the Company proposes that all variances from the costs under the formulae for the controllable items be included. Requiring the Company to track and otherwise validate or pre-approve investments in restructuring and efficiency gains also moves away from the objectives of implementing PBR.

In view of the questions raised at the Workshop and in the IRs relating to the FTEI proposal, Terasen Gas is willing to consider alternative approaches to providing continuing incentives as part of the upcoming NSP. For example, it may be possible to achieve a similar outcome sought by the proposed FTEI by constructing an alternative phase out mechanism. In the 1998 – 2001 PBR, the capital efficiency mechanism had a simple form of phase out that would not raise the same concerns expressed by parties as to tracking and validating investments in efficiency. The Company is prepared to explore alternatives such as a simple phase out of the final year variances in the controllable cost items for the four years following the PBR term. This could accomplish much the same result in terms of providing continuing incentives through the term of the PBR and be administratively simpler to implement.

What safeguards exist to avoid cross-subsidization of NRBs by developing programs which may benefit those companies at the expense of Utility customers?

Response

The Code of Conduct and Transfer Pricing Policies provide safeguards to protect customers' interests. During the PBR term, the Company and its employees would continue to be subject to both the Code of Conduct and the Transfer Pricing Policy. In addition, cross-subsidization would reduce the Company's earnings under the sharing mechanism, impair the recovery of restructuring costs, and reduce the customer benefit under the PBR Plan which would reduce the willingness of stakeholders to enter into PBR settlements in the future.

Why should a five-year recovery period be allowed as opposed to a three-year recovery period?

Response

The recovery period under the proposed FTEI is actually four years, and is based on the principle that the Company should be encouraged to make investments and take the associated risks and generate efficiencies throughout the term of the PBR Plan. As outlined in the FTEI example in Appendix C-2, the Company's share of the benefits generated by first year investments are available for the full term (i.e. the year in which they are made plus four more years) but do not carry over beyond the end of the term. Second year investments carry over for one year post term, and so on such that the fifth year generated benefits carry on until 2012 or four years post term.

1.9.2 *The incremental annual savings from the FTEI is defined on page 2 as the sum of the current year O&M savings and the current year plant additions savings multiplied by a factor of 15 percent. The 15 percent factor is described as representing the average avoided annual revenue requirement associated with plant additions. Based on the example shown on page 4 please provide a supporting calculation for the 2004 formula based plant additions of $138.4 million compared to 2004 actual plant additions of $132.4 million to demonstrate that the avoided annual revenue requirement would be $0.9 million*.

Response

Support for the 15% factor is found in the cost of service analysis below. The analysis displays the revenue requirement impact of $100,000 of plant additions using the following assumptions:

- Plant additions reflect the same mix of plant additions by BCUC account as used in the PBR formula. Tax savings for the net-of-tax treatment of computer software are also incorporated.
- The capital structure, debt interest rates and ROE are as follows:
  - Short-term debt at 8% of capital structure and 5% rate.
  - Long-term debt at 59% of capital structure and 7% coupon rate (7.142% effective rate).
  - Equity at 33% of capital structure and 9.5% ROE.
- A levelized annual revenue requirement which equates on a present value basis to the calculated yearly revenue requirements

As can be seen from the table, the levelized annual revenue requirement over five years is 13.2% of the gross plant addition (Line 50). For purposes of the FTEI a factor of 15% will be used to calculate the avoided plant additions benefit. Adopting a fixed factor of 15% is a simplifying approach which avoids a complex calculation of the differences between plant additions allowed by the formula and actual plant additions. The difference between 13.2% and 15% allows for capital savings that might be weighted more to plant accounts with higher depreciation rates and for the possibility that the cost of capital could be higher in the future. Beyond this, the FTEI calculation shares the plant additions benefit 50/50 with customers, so only 7.5% is carried forward. Also, customers' rates will include the benefits of the lower plant additions for many years into the future.

TERASEN GAS INC.
ANALYSIS OF 15% PLANT ADDITIONS BENEFIT FACTOR
RATE BASE AND EARNED RETURN
($000)

Line No.	Particulars			2004	2005	2006	2007	2008	2009
1	GAS PLANT IN SERVICE								
2	Gross Plant - beginning of year			$ 0	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
3									
4	Additions			100,000	0	0	0	0	0
5									
6	Contribution in aid of construction								
7	Beginning of year			$ 0	$ (3,361)	$ (3,361)	$ (3,361)	$ (3,361)	$ (3,361)
8	Additions			(3,361)	0	0	0	0	0
9									
10	End of year			$ (3,361)	$ (3,361)	$ (3,361)	$ (3,361)	$ (3,361)	$ (3,361)
11									
12	Less - Accumulated Depreciation			0	(3,792)	(7,584)	(11,376)	(15,168)	(18,960)
13									
14	Net plant - end of year			$ 96,639	$ 92,847	$ 89,055	$ 85,263	$ 81,471	$ 77,679
15									
16	Mid-Year Unamortized Deferred Charges			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
17									
18	WORKING CAPITAL			$ 966	$ 1,928	$ 1,891	$ 1,853	$ 1,815	$ 1,777
19									
20	13 MONTH AVERAGE RATE BASE			$ 49,285	$ 96,671	$ 92,842	$ 89,012	$ 85,182	$ 81,352
21									
22	RATE BASE CAPITALIZATION								
23		59.00%	L-T Debt	$ 29,078	$ 57,036	$ 54,777	$ 52,517	$ 50,257	$ 47,998
24		8.00%	Unfunded	3,943	7,734	7,427	7,121	6,815	6,508
25		0.00%	Preference	0	0	0	0	0	0
26		33.00%	Equity	16,264	31,901	30,638	29,374	28,110	26,846
27									
28	Return on :								
29	Long Term Debt @		7.14%	$ 2,077	$ 4,074	$ 3,912	$ 3,751	$ 3,589	$ 3,428
30	Unfunded Debt @		5.00%	197	387	371	356	341	325
31	Preference @		0.00%	0	0	0	0	0	0
32	Equity @		9.50%	1,545	3,031	2,911	2,791	2,670	2,550
33									
34	Earned return			3,819	7,492	7,194	6,898	6,600	6,303
35	Expenses			0	3,792	3,792	3,792	3,792	3,792
36	Income taxes			(215)	1,375	1,553	1,647	1,779	1,875
37									
38	Cost of Service			$ 3,604	$ 12,659	$ 12,539	$ 12,337	$ 12,171	$ 11,970
39	Other Revenues - Connection Charge			0	0	0	0	0	0
40	Sales Revenue Margin			0	0	0	0	0	0
41									
42	REVENUE EXCESS (DEFICIENCY)			$ (3,604)	$ (12,659)	$ (12,539)	$ (12,337)	$ (12,171)	$ (11,970)
43	PV of C.O.S. @		6.11%	$ (3,604)	$ (11,930)	$ (11,137)	$ (10,326)	$ (9,601)	$ (8,898)
44	Cumulative PV			$ (3,604)	$ (15,534)	$ (26,671)	$ (36,997)	$ (46,597)	$ (55,496)
45									
46	LEVELIZED REVENUE EXCESS (DEFICIENCY)				(13,214)	(13,214)	(13,214)	(13,214)	(13,214)
47	PV of C.O.S. @		6.11%		(12,453)	(11,736)	(11,060)	(10,423)	(9,823)
48	Cumulative PV				(12,453)	(24,189)	(35,249)	(45,673)	(55,496)
49									
50	Revenue Requirement Impact as % of Gross Plant Additions (Line 8)				-13.21%	-13.21%	-13.21%	-13.21%	-13.21%

1.10 Reference: Application, Tab C, Appendix C-A-1

1.10.1 *Please clarify if the Service Quality Indicator ("SQI") of "Response Time to Site for Emergency Calls" records the time from when the call is received (e.g. at the call centre) or from the time that Utility staff are dispatched to the incident. If it is from the time of dispatch, please provide the historical response times from the time the call is received that corresponds to the information on page 7 of Appendix C-A-1*.

Response

Since 1998, Terasen Gas has tracked emergency response time as the time from dispatching an employee to the time that employee arrives on site. As of January 1, 2003 Terasen Gas can track the time that emergency call information is captured by CustomerWorks (the time that the work order is raised and sent to Terasen Gas dispatch).

CustomerWorks gathers all the emergency call information and then e-mails the information to Terasen Gas Dispatch. CustomerWorks follows this e-mail up with a phone call to ensure that Terasen Gas Dispatch received the emergency call information.

Technology limitations do not allow Terasen Gas to track the time the emergency call is received by CustomerWorks.

Although Terasen Gas can now track the emergency response time from the time CustomerWorks captures the emergency call information to the time an employee or authorized Utility representative arrives on site Terasen Gas will continue to report for the Service Quality Indicator the time from an employee being dispatched to arriving on site. This measure matches the historical tracking and proposed benchmark for emergency response.

1.10.2 *With respect to the three CustomerWorks performance measures that Terasen Gas proposes to combine into one Billing Performance SQI, please discuss whether there are trade-offs between the three measures, and the disadvantages of treating them as three separate SQI's*.

Response

Terasen Gas does not believe there are any advantages or disadvantages to treating the three billing indicators as separate SQIs for the purposes of reporting to the BCUC. The intent of the composite scoring methodology is to provide a method that would reflect, in a single indicator, the end to end business process related to billing activities rather than focusing on a portion of the process.

The purpose in tracking the three components internally as separate measures is to ensure that trade-offs are not made to the disadvantage of customers. Each of the three criteria (accuracy, timeliness and completeness) is considered equally important and bear the same weighting in terms of penalties in the Client Services Agreement.

1.10.3 *What penalties apply to CustomerWorks if it fails to meet one or more of the performance measures? Would Terasen Gas propose to flow any financial penalties received through to customers*?

Response

Penalties are included in the Client Services Agreement in a number of areas including: speed to answer for emergency and non-emergency calls, billing accuracy, billing timeliness and billing completeness.

Penalties assessed are offset against service fees billed. Under the proposed PBR Plan, any financial penalties collected by Terasen Gas under the Client Services Agreement would be shared with Customers as offsets to O&M expense.

1.10.4 *Recognizing that Terasen Gas has identified concerns about using "Number of Third Party Distribution System Incidents" and "Leaks per Kilometre of Distribution Mains" as SQI's, it would nevertheless appear that, in the pursuit of excellence and continuous improvement, that these measures should be expected to trend downward over time. Please identify the three year average for 2000, 2001, and 2002 for each measure. What are the pros and cons of a benchmark that expects the rolling three year average to be stable or decline (that is, that the average for 2002, 2003 and 2004 should be equal to or less than the average for 2001, 2002 and 2003)*.

Response

	2000	*2001*	*2002*
Third Party Incidents per 1,000 Housing Starts	76.7	74.2	73.6
Leaks per Km of Distribution Main	.0044	.0039	.0041

Terasen Gas has concerns about using these SQIs as measures for a number of reasons.

The correlation between third party incidents and housing starts is difficult to ascertain.

In addition, the leaks per kilometre of distribution main measure was designed to recognize that a low number of leaks on the premise that a system with fewer leaks was in better condition than one with many leaks. Terasen Gas policies and the new Preventative Maintenance (PM) system are all designed to find as many leaks /

problems as possible and fix them. This will result in an increase in the number of leaks as attention is focused on upgrading problem areas. The result is a better system.

These measures may ultimately trend downwards in the long term, however that is not the anticipated result over the next 3 to 5 years.

1.10.5 *The SQIs "Response Time to Site for Emergency Calls" and "Transmission System Annual Reportable Incidents", could also be considered safety related measures. Please discuss the pros and cons of a benchmark that expects the rolling three-year average of each to be stable or decline*.

Response

Terasen Gas has put extensive effort into redesigning its business processes and reducing its field operating costs over the past five plus years. During this time, costs were reduced but it became a struggle to keep reducing the response time for emergency calls. Terasen Gas has been successful in achieving significant operational efficiencies. However, it is not reasonable to expect to see a continually declining response time and a further reduction in labour costs. A reasonable balance of cost and response time has been achieved.

The number of transmission incidents is particularly low at two per year. This measure has been stable over the past several years and is not expected to vary. A declining three-year average would not make sense on such a small measure.

1.10.6 *Because of the importance of safety, should Terasen Gas be required to meet the benchmark for each of four safety-related SQI's:*

- *Response Time to Site for Emergency Calls*
- *Transmission System Annual Reportable Incidents*
- *Number of Third Party Distribution System Incidents*
- *Leaks per Kilometer of Distribution Mains*

in order to receive a positive incentive payment under a PBR mechanism for 2004/2008?

Response

Terasen Gas is proposing to include the first two SQIs (Response Time to Site for Emergency Calls and Transmission System Annual Reportable Incidents) but not the last two SQIs (Number of Third Party Distribution System Incidents and Leaks per Kilometre of Distribution Mains).

The excluded SQIs have however been retained as directional indicators but Terasen Gas does not agree that these two indicators should be included in any benchmark that determines incentive payment eligibility.

Terasen Gas believes that the issue of whether or not the achievement of the balance safety SQIs should be used to qualify the Company for an incentive should be dealt with similar to the way it was handled in the 1998 – 2001 PBR. In that PBR plan, the treatment of incentives were subject to Commission discretion as opposed to being absolute if the Company failed to perform on its SQIs. There may arise circumstances beyond the Company's control that could yield results outside the target levels of performance and the Commission could be expected to exercise its judgement in such circumstances. Please see also the response to LMLGUA et al Question 32.

In all previous PBRs utilities have been accountable for SQIs to the extent that they could not profit from the financial incentives unless the service quality was always maintained. Why should this change now?

Response

The proposal put forward in this PBR is to put in place a mechanism that incents the Company to achieve efficiencies while maintaining service quality. This is consistent with the way SQIs worked in the 1998 - 2001 PBR. The difference in the current proposal is that the current level of performance should be maintained rather then set the targets each year at the three-year rolling average.

1.10.7 *Should Terasen Gas be required to meet the benchmark of at least three of the other four SQIs:*

- *Speed of Answer – Emergency*
- *Speed of Answer – Non-emergency*
- *Billing Performance*
- *Meter Exchange Appointment Compliance*

in order to receive a positive incentive payment under a PBR mechanism for 2004/08?

Response

No. Incentive payments should not necessarily depend on meeting the performance targets. Although the Company expects to meet the targets on an annual basis, the targets related to CustomerWorks activities have been set at the maximum negotiated under the Client Services Agreement. The Company would not expect CustomerWorks to exceed these targets unless additional funding was provided to support a higher level of service than has been defined in the Agreement. If a significant or force majeure event should cause CustomerWorks to under-perform in the short term, there is no incentive in the Agreement to support significant over-performance in other periods to ensure recovery to the target set.

Please also see the response to Question 1.10.6 above.

1.11 Restructuring Deferral Account
Reference: C-6, C-15 to C-16 and Appendix C-A-2

The Application proposes that investments in restructuring that are incurred by the Company after the Commission approves the PBR Plan should be recorded in a deferral account with recovery commencing in 2004 as an offset to realized efficiencies.

1.11.1 *One of the issues raised at the Pre-hearing Conference was a request that Terasen Gas provide a definition of restructuring costs. Please define restructuring costs and provide examples of a restructuring initiative, the calculation of expected costs and the estimated savings. Please explain if expenditures on other cost saving measures would also be recorded in this deferral account*.

Response

The Application proposes that the restructuring costs be captured in a Restructuring Cost tracking account and that the Company be allowed to recover these costs out of increased earnings prior to the commencement of 50:50 sharing with customers. Under the 1997 Settlement the customers contributed $3 million to a restructuring account and shared the balance of the restructuring costs through the earnings sharing mechanism. The Company believes the current proposal is more beneficial to customers.

The Company proposes that restructuring costs would include:

- Involuntary termination costs and other early termination benefits; including payments in lieu of notice, early retirement incentives, payments in lieu of benefits, other inducements;
- Costs associated with suspending operations or terminating a contract; such as those related to lease terminations or sub-leasing related costs, employee relocation and re-training, facilities move costs, equipment dismantle and move costs, outplacement services and career transition costs;
- Consulting fees relating to the development of and or execution of restructuring plans;
- Investments in the conversion of systems and processes; such as costs to move to common computer platforms ; and
- Other costs as allowed for under the CICA Handbook relating to restructuring.

An example of a restructuring initiative is the Productivity Enhancement Program (PEP) that the Company undertook at the start of the last PBR Plan. Consultants were engaged to assist in assessing opportunities and develop plans to rationalize the operations, offices were closed, employees relocated or terminated, etc. The costs associated with this program under the definition above would be captured as restructuring costs under the current proposal. The savings associated with this past initiative were lower labour and related costs, and reduced facilities costs.

The total staff reductions during the past PBR excluding the CustomerWorks outsourcing arrangement were approximately 265 FTEs and the costs associated with the restructuring totalled $12.4 million of which customers provided an upfront contribution of $3 million and shared half of the balance.

The Company does not believe that it is possible to attempt to reduce labour costs by a similar order of magnitude over the next five years. Therefore, neither the costs nor savings would approach similar levels. At the present time, the Company cannot estimate the potential savings of further restructuring, however the adjustment factor of 0.75% proposed in the Application yields a reduction of on average approximately $3.25 million off the inflation adjusted revenue requirements each year under the formula so the Company will be highly incented to pursue whatever opportunities do exist just to achieve the allowed rate of return.

As indicated in the response to Question 1.9.1 above, the concept of recovery of restructuring costs out of realized benefits prior to the commencement of sharing is a concept separate and distinct from the FTEI mechanism. While the Company believes that this is an enhancement to the 1998 - 2001 PBR Plan, it is willing to consider a sharing mechanism similar to that included in that Plan.

1.11.2 *At the Workshop, Terasen Gas explained that if a restructuring initiative did not result in benefits in five years, the unamortized costs would be charged to the shareholders. Please explain how the estimated savings will be determined in order to allow amortization of restructuring costs. Will Terasen Gas be identifying its 2003 Decision baseline activities and costs then comparing the cost savings that result from a restructuring initiative? If yes, when would Terasen Gas inform the intervenors-at the Annual Reviews, at the Mid Term Review or five years after a restructuring initiative has been undertaken*?

Response

The Company proposes that positive variances from the allowed ROE would be retained by the Company in order to recover restructuring costs. The Company does not propose to attempt to reconcile cost savings with specific initiatives. Restructuring costs that meet the definition of those costs will be recorded in the Restructuring Cost tracking account. At each Annual Review the Company will report the activity in the Restructuring Cost tracking account and project its results of operations for the current year and estimated impact on the Restructuring account and the earnings sharing mechanism. The Company would also report each year the incremental benefits (or costs) achieved each year for controllable items that, pursuant to the FTEI, would be subject to carry over beyond the term of the PBR.

1.11.3 *Terasen Gas explains in Appendix C-A-2 that, normally, companies use a net present value analysis to evaluate investment decisions, comparing the cost of the investment to the discounted value of the stream of savings resulting from the investment. However, rather than identifying the savings resulting from the initial investment, the Terasen Gas sharing mechanism assumes that any differences between formula-based expenses and actual expenses will be due to the Terasen Gas efficiency expenditures captured in the proposed deferral account.*

Workshop participants were concerned that there is no identifiable link between the efficiency expenditures and the "savings", while Terasen Gas was reluctant to submit its efficiency investment proposals to the Commission for review. The problem is exacerbated by the use of the FTEI to extend the "savings" period.

Can Terasen Gas suggest any means to reduce these concerns?

Response

As discussed at the Workshop, efficiencies will be generated from a number of activities beyond large one time initiatives where it will be very difficult to link costs and achieved benefits. The proposal as set out in the Application is that the cost of for these initiatives would not be included in the Restructuring Cost tracking account.

Similarly, incremental costs beyond the control of the Company will erode the benefits generated by these initiatives, and this erosion of benefit will reduce both the recovery of restructuring costs and the amount of benefits retained by the Company beyond the term of the PBR Plan. It is impractical to attempt to track benefits initiative by initiative. Further, the proposal is not to track all investments of time and resources in generating efficiencies to be recovered first before the commencement of sharing, but rather only those costs that meet the strict definition of Restructuring Costs.

The Company understands stakeholders concerns regarding unearned rewards and the proposal being made is intended to align the Company's and customer interests without overwhelming administrative burden. As indicated in the response to Question 1.11.1 above, Terasen Gas is willing to explore alternative approaches similar to the 1998 - 2001 PBR.

1.11.4 *Page C-15 states that if a debit balance remains in the restructuring deferral account at the end of 2008, incremental earnings from the Full Term Efficiency Incentive will be used to reduce or eliminate the residual balance. Does this proposal mean that cost recovery on a restructuring initiative will only occur for five years? Will there be a streaming of the cost recovery to an initiative to enable the five-year cost recovery analysis*?

Response

The Company is proposing to retain a share of the incremental benefits generated each year during the PBR term for a period of five years (the year of the expenditure plus four more years). This is illustrated in the example in Appendix C-2.

The balance of the Restructuring Cost tracking account could zero out during the term and then accumulate again later in the term for new initiatives that had associated restructuring costs. The illustration in Appendix C-2 shows this happening. At the end of the term, should a balance exist, it could continue to be tracked to show the recovery of costs during the post PBR period. As a practical matter, this would not really be necessary as the Company's share of post PBR benefit retention would be recovered in a declining rider and the unrecovered restructuring costs would not be relevant.

1.11.5 *Does Terasen Gas propose that the restructuring deferral account be a rate base or non-rate base account? If a restructuring initiative may not result in sufficient savings to recover the cost of the project, why should rate base treatment of the restructuring costs be appropriate instead of a non-interest bearing, non-rate base deferral account*?

Response

Terasen Gas is proposing that this be treated as a non-rate base account. The account is intended only as a tracking mechanism to determine when restructuring costs have been recovered.

2.0 Reference: Application, Tab D, Section H, Tab 3

2.1 *Terasen Gas projects the Net Gas Plan in Service ("NGPiS") at mid year 2003 as $2,149.0 million and at the end of 2003 as $2,166.8 million. The calculation of gross plant in service is described on page 2 of Section H, Tab 3. Please explain how the Accumulated Depreciation and CIAC numbers used in the calculation will relate to the corresponding amounts (presumably based on actual data) that eventually will be recorded in the Utility's financial accounts*.

Response

The formula approach for Net Gas-Plant-in-Service calculates Accumulated Depreciation and Contributions in Aid of Construction ("CIAOC") based on the gross plant-in-service and the annual net plant additions that fall out of the formula and for CIAOC other drivers such as customer additions. For rate setting purposes the formula-derived values of these items are carried forward throughout the five year period and are not rebased. Accumulated Depreciation is based on the formula-derived plant additions and gross plant in service. The formula-derived plant additions are distributed to the various plant accounts based on the five-year capital forecast average percentages. The annual depreciation provision is based on the approved depreciation rates by account (including the approved depreciation rate increases in meters and computer software starting in 2004).

Actual results for all of these items will be accounted for on the same basis as has been approved by and reported to the Commission historically. In other words the Company will record in rate base each year actual gross plant-in-service, actual accumulated depreciation and actual CIAOC based on recorded activity in these accounts. The formula-based and actual amounts for gas-plant-in-service, accumulated depreciation and CIAOC will diverge over time if the Company is able to find efficiencies and reduce capital spending below the formula-derived amounts. This leads to a portion of the incentive and the earnings sharing implicit in the PBR Plan.

2.2 *Please describe how Line 17 (Net Plant Addition) of Section H, Tab 3, p. 2.2 is determined. Line 10 of the illustrative example on page 4 of Appendix C-A-2 shows Plant Additions from the PBR formula. Should this information correspond to Line 17 of page 2.2, Section H, Tab 3? If not, please explain how Line 10 of the illustrative example would be determined*.

Response

The description of how Net Plant Additions is determined is found in Section H, Tab 3, Pages 2 and 2.1. As described there, the formula works backwards from the mid-year Net Gas-Plant-in-Service through several steps to determine the current year ending gross plant in service. The beginning gross plant in service (i.e. the prior year's ending gross plant in service) is deducted from the ending gross plant in service to determine the net plant additions. Net plant additions consist of gross plant additions less retirements.

The break out of gross plant additions and retirements is found in Section H, Tab 3, Pages 2.3 and 2.4. The illustrative example on Page 4 of Appendix C-A-2 uses the gross plant additions from Tab 3, Pages 2.3 and 2.4. The net plant additions on Line 17 of Section H, Tab 3, Page 2.2 is equal to gross plant additions less retirements on Section H, Tab 3, Pages 2.3 and 2.4. Using 2004 as an example net plant additions of $117,225,000 (Tab 3, Page 2.2, col. 4, line 17) are equal to gross plant additions of $138,364,000 (Tab 3, Page 2.4, col. 3, line 31) less retirements of $21,139,000 (Tab 3, Page 2.4, col. 4, line 31). The illustrative example in Appendix C-A-2 uses $138.4 million for 2004 plant additions which is consistent with the gross plant additions in Tab 3, Pages 2.3 and 2.4.

2.3 *Why does Terasen Gas believe using the proposed formula based on NGPiS will give more reliable results than basing the formula on gross plant in service, and then deducting accumulated depreciation and CIAC, in order to calculate NGPiS for future years*?

Response

The intent was to develop a PBR formula that related allowed revenue requirements to the two main constituent parts of rates: rate base and O&M.

Terasen Gas developed the capital formula based on Net Gas-Plant-in-Service since it is the main constituent of rate base. This approach establishes a formula that ensures that costs in the controllable categories of capital and O&M used for rate setting purposes will increase by less than inflation. If the formula was to be based on gross plant in service there would not be the same direct link between the capital-related component of the formula and rate base which determines a significant component of the overall cost of service.

2.4 *Please discuss the pros and cons of forecasting annual capital additions by using a PBR-type formula that is based on base year capital expenditures, rather than on NGPiS or rate base*.

Response

One of the major benefits of the enhancement proposed by the Company under the Net Gas-Plant-in-Service approach vs. the 1998 - 2001 PBR capital formulas is that it is geared to managing overall rate base which drives revenue requirements and hence customer rates and is focused on achieving Net Gas-Plant-in-Service related rate base decreases in real terms over time. The proposal is much more comprehensive in that it covers CPCNs in addition to base capital. CPCNs are by their nature project specific and have a non-linear cost profile so are not readily susceptible to a formula approach driven off a base year expenditure.

The base year capital expenditure based formula would not cover CPCNs which a number of stakeholders suggested was a shortcoming of the previous PBR.

The unit cost based formulas for new customer attachment related capital in the 1998 PBR were impacted by changes in customer growth both in absolute numbers and geographic dispersion. These factors created significant unanticipated impacts under the previous capital efficiency mechanism.

The 1998 - 2001 PBR capital formulas segmented the elements of capital expenditures and the incentives were heavily biased in favour or O&M savings over capital. The capital incentive/penalty period was very muted. Because the Net Gas-Plant-in-Service approach is more comprehensive than the 1998 - 2001 PBR capital formulas, it provides less of a bias towards O&M savings than did the previous Plan.

The Company believes that a more comprehensive approach to capital expenditures is desirable as proposed in the current Application.

2.5 *Further to the information on page D-5, please provide a table for years 1997 to 2002 that shows gross and net plant in service at the start, mid-year and end of each year, the regular capital additions and CPCN additions during the year (shown separately, with the AM/FM project costs included with CPCNs), the CPI and average number of customers for each year.*

Response

The table for years 1997 to 2002 that shows gross and net plant in service at the start, mid-year and end of each year, the regular capital additions and CPCN additions during the year (shown separately, with the AM/FM project costs included with CPCNs), the CPI and average number of customers for each year is shown below.

Description	1997 Normal	1998 Normal	1999 Normal	2000 Normal	2001 Normal	2002 Normal
(1)	(3)	(4)	(5)	(6)	(7)	(8)
Plant in service, Beginning	$1,731,549	$1,835,587	$1,915,010	$2,043,616	$2,094,851	$2,566,808
CPCN's (adjusted for AM/FM costs)	2,292	10,689	29,643	3,016	418,195	50,299
Additions / Transfers (adjusted for AM/FM costs)	110,887	97,246	104,252	104,788	99,707	107,352
Disposals	(9,141)	(28,512)	(5,289)	(52,528)	(24,799)	(27,664)
Plant in service, Ending	1,835,587	1,915,010	2,043,616	2,098,892	2,587,954	2,696,795
Add - Intangible plant	882	837	837	837	837	837
	1,836,469	1,915,847	2,044,453	2,099,729	2,588,791	2,697,632
Contributions in aid of construction	(61,644)	(79,039)	(98,420)	(109,570)	(132,585)	(134,289)
Less - Accumulated depreciation / amortization	(274,612)	(297,359)	(353,285)	(376,000)	(421,171)	(459,971)
Net plant in service, Ending	$1,500,213	$1,539,449	$1,592,748	$1,614,159	$2,035,035	$2,103,372
Net plant in service, Beginning	$1,447,874	$1,506,300	$1,565,902	$1,592,748	$2,024,032	$2,075,155
Net plant in service, Mid-year	$1,474,044	$1,522,875	$1,579,325	$1,603,454	$2,029,534	$2,089,264
CPI	0.70%	0.30%	1.10%	1.90%	1.70%	2.30%
Average Number of Customers	720,464	734,152	745,234	755,079	760,236	766,929
AM/FM originally included as Capital Additions but reclassified as CPCN	$0	$4,602	$3,190	$3,016	$4,281	$0

2.6 *Based on the foregoing information, please calculate the total mid-year NGPiS, excluding CPCN additions after 1997. Please also use the historical NGPiS of $2046 per customer in 1997 and the proposed PBR formula for 2004/08 to calculate the total mid-year NGPiS by year through 2002 according to the formula*.

Response

The information above, excluding CPCN additions after 1997, using the historical Net Gas-Plant-in-Service of $2,046 per customer in 1997 and the proposed PBR formula for 2004/08 to calculate the total mid-year Net Gas-Plant-in-Service by year through 2002 according to the formula, is shown in the table below.

Line No.	Description	1997	Increase	1998	Increase	1999	Increase	2000	Increase	2001	Increase	2002
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Annual Inflation Rate - CPI		0.30%		1.10%		1.90%		1.70%		2.30%	
2	Adjustment Factor Used for Capital Calculations		0.75%		0.75%		0.75%		0.75%		0.75%	
3												
4	Average Number of Customers	720,464	13,688	734,152	11,082	745,234	9,845	755,079	5,157	760,236	6,693	766,929
5	Percentage Growth in Average Customers		1.90%		1.51%		1.32%		0.68%		0.88%	
6												
7	Net Plant in Service, Mid-Year	$1,474,044	$21,247	$1,495,291	$27,885	$1,523,176	$37,866	$1,561,043	$25,593	$1,586,635	$38,779	$1,625,414
8												
9	Mid YearPlant In Service Per Average Customers											
10	(Line 7 divided by Line 4) - In Dollars	$2,045.96		$2,036.76		$2,043.89		$2,067.39		$2,087.03		$2,119.38
11			-0.45%		0.35%		1.15%		0.95%		1.55%	
12	Increase in Line 10: Line 10 x (1+Inflation- Adjustment Factor) - L		($9.20)		$7.13		$23.50		$19.64		$32.35	
13												
14	Line 10 x Line 4 = Line 7 - Net Plant in Service Mid Year			$1,495,291		$1,523,176		$1,561,043		$1,586,635		$1,625,414
15												
16	Plant in Service (Gross), Beginning	$1,731,549		$1,835,587		$1,865,930		$2,006,852		$2,050,835		$2,160,088
17	Net Plant Additions	104,038		30,343		140,922		43,983		109,253		76,994
18	Plant in Service (Gross), Ending	1,835,587		1,865,930		2,006,852		2,050,835		2,160,088		2,237,082
19	Add - Intangible Plant	882		837		837		837		837		837
20	Less: Contributions In Aid of Construction	(61,644)		(79,039)		(98,420)		(109,570)		(132,585)		(134,289)
21	Accumulated Depreciation	(274,612)		(297,359)		(353,285)		(376,000)		(421,171)		(459,971)
22	Net Plant in Service, Ending	1,500,213		1,490,369		1,555,984		1,566,102		1,607,169		1,643,659
23												
24	Net Plant in Service, Beginning	$1,447,874		$1,500,213		$1,490,369		$1,555,984		$1,566,102		$1,607,169
25												
26	Net Plant in Service, Mid-Year	$1,474,044	$21,248	$1,495,291	$27,885	$1,523,176	$37,866	$1,561,043	$25,593	$1,586,635	$38,779	$1,625,414

3.0 Reference: Application, Tab D, Section H, Tab 3

3.1 *Further to page D-5, please explain the difference between the "Decision" and "Cost of Service" NGPiS per customer, summarizing how each was calculated. Please provide the total mid-year NGPiS in nominal dollars for both forecasts for each year. On the same table, please show the total NGPiS according to the proposed PBR formula as set out in Section H, Tab 3, page 2.2 and the NGPiS based on the detailed Categories A, B, C, D information on pages D-5 to D-32 (if the latter is not one of the other forecasts)*.

Response

The difference between the "Decision" and the "Cost of Service" Net Gas-Plant-in-Service per customer is the capitalized overhead from O&M between the two forecasts. The higher annual O&M in the "Cost of Service" forecast is reflected in the higher net plant throughout the years. The calculations of the Net Gas-Plant-in-Service per customer for each of the forecasts are shown in the table below.

MID-YEAR NET GAS-PLANT-IN-SERVICE (NGPiS)

Line No.	Particulars	Decision 2003	Projected 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Mid-Year NGPiS $000 Nominal							
2								
3	Decision	$2,154,871	$2,148,959	$2,187,136	$2,216,930	$2,260,388	$2,349,086	$2,372,928
4								
5	Cost of Service	$2,154,871	$2,148,959	$2,187,621	$2,218,343	$2,262,701	$2,352,306	$2,377,052
6								
7	PBR Formula	$2,154,871	$2,148,959	$2,192,745	$2,244,291	$2,297,270	$2,351,881	$2,407,484
8								
9	Average Customers	775,145	775,492	783,070	791,584	800,267	809,177	818,082
10								
11	$ Nominal per Customer							
12								
13	Decision	$2,780	$2,771	$2,793	$2,801	$2,825	$2,903	$2,901
14								
15	Cost of Service	$2,780	$2,771	$2,794	$2,802	$2,827	$2,907	$2,906
16								
17	PBR Formula	$2,780	$2,771	$2,800	$2,835	$2,871	$2,907	$2,943

3.2 *Please provide a table showing, by year for the PBR period and for each of the foregoing forecasts, the NGPiS addition (increase) and the corresponding annual capital addition that would apply for the capital additions incentive calculation. Where possible, such as the Categories A, B, C, D forecast, please show both the total NGPiS increase and a breakout for CPCN projects and other*.

Response

The requested information is provided in the following tables.

MID-YEAR NET GAS-PLANT-IN-SERVICE (NGPiS)
$000 NOMINAL

Line No.	Particulars	Decision 2003	Projected 2003	NGPiS Change	Forecast 2004	NGPiS Change	Forecast 2005	NGPiS Change	Forecast 2006	NGPiS Change	Forecast 2007	NGPiS Change	Forecast 2008	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**Mid-Year NGPiS**													
2														
3	Decision	$2,154,871	$2,148,959	$38,177	$2,187,136	$29,794	$2,216,930	$43,458	$2,260,388	$88,698	$2,349,086	$23,842	$2,372,928	
4														
5	Cost of Service	$2,154,871	$2,148,959	$38,662	$2,187,621	$30,722	$2,218,343	$44,358	$2,262,701	$89,605	$2,352,306	$24,746	$2,377,052	
6														
7	PBR Formula	$2,154,871	$2,148,959	$43,786	$2,192,745	$51,546	$2,244,291	$52,979	$2,297,270	$54,611	$2,351,881	$55,603	$2,407,484	
8														
9														
10					Plant		Plant		Plant		Plant		Plant	
11					Additions		Additions		Additions		Additions		Additions	
12	**Plant Additions Arising From:**				2004		2005		2006		2007		2008	
13														
14	**Decision**													
15	Categories A, B & C Additions				$83,098		$83,156		$87,641		$82,664		$83,611	$420,170
16	CPCN Additions				9,673		9,436		23,097		69,120		7,687	119,013
17	Capitalized Overhead				26,260		27,089		28,296		29,483		30,424	141,552
18	Total Decision				$119,031		$119,681		$139,034		$181,267		$121,722	$680,735
19														
20	**Cost of Service**													
21	Categories A, B & C Additions				$83,098		$83,156		$87,641		$82,664		$83,611	$420,170
22	CPCN Additions				9,673		9,436		23,097		69,120		7,687	119,013
23	Capitalized Overhead				27,229		27,998		29,251		30,449		31,416	146,343
24	Total Cost of Service				$120,000		$120,590		$139,989		$182,233		$122,714	$685,526
25														
26	**PBR Formula**				$138,364		$141,568		$149,832		$149,230		$156,684	$735,678

SUMMARY OF CAPITAL EXPENDITURES AND GAS PLANT IN SERVICE ADDITIONS
DECISION AND COST OF SERVICE FORECASTS
FOR THE YEARS 2004 TO 2008
$000

Line No.	Particulars	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
	(1)	(2)	(3)	(4)	(5)	(6)
1	**CAPITAL EXPENDITURES**					
2						
3	**Capital Expenditures - Categories A, B & C**					
4	A: Mains, Services & Meters	$32,812	$33,794	$34,792	$35,869	$36,942
5	B: Systems Integrity and Reliability	25,064	17,310	21,977	14,931	15,230
6	C: All Other Plant	27,195	28,627	30,167	30,771	31,402
7						
8	**TOTAL - Categories A, B & C**	**$85,071**	**$79,731**	**$86,936**	**$81,571**	**$83,574**
9						
10	**Capital Expenditures - Category D (CPCN)**					
11	Transmission Pipeline Integrity Plan	$9,137	$10,149	$4,502	$4,539	$4,630
12	Nichol to Coquitlam Loop		12,360	10,826		
13	Naramata Loop			31,991		
14	Kitchener B Compressor Unit Addition			19,389		
15						
16	**TOTAL - Category D (CPCN)**	**$9,137**	**$22,509**	**$66,708**	**$4,539**	**$4,630**
17						
18	**TOTAL CAPITAL EXPENDITURES**	**$94,208**	**$102,240**	**$153,644**	**$86,110**	**$88,204**
19						
20						
21	**ADDITIONS TO GAS PLANT IN SERVICE**					
22						
23	Capital Expenditures - Categories A, B & C	$85,071	$79,731	$86,936	$81,571	$83,574
24	Net WIP and AFUDC Changes	(1,973)	3,425	705	1,093	37
25	**Total Additions - Categories A, B & C**	**$83,098**	**$83,156**	**$87,641**	**$82,664**	**$83,611**
26						
27	Capital Expenditures - Category D (CPCN)	$9,137	$22,509	$66,708	$4,539	$4,630
28	Net WIP and AFUDC Changes	536	(13,073)	(43,611)	64,581	3,057
29	**Total Additions - Category D**	**$9,673**	**$9,436**	**$23,097**	**$69,120**	**$7,687**
30						
31	**TOTAL ADDITIONS - CATEGORIES A, B, C & D**	**$92,771**	**$92,592**	**$110,738**	**$151,784**	**$91,298**
32						
33	Overhead Capitalized - Decision	26,260	27,089	28,296	29,483	30,424
34						
35	**TOTAL PLANT ADDITIONS - DECISION**	**$119,031**	**$119,681**	**$139,034**	**$181,267**	**$121,722**
36						
37	Overhead Capitalized Difference					
38	from Decision to Cost of Service	969	909	955	966	992
39						
40	**TOTAL PLANT ADDITIONS - COST OF SERVICE**	**$120,000**	**$120,590**	**$139,989**	**$182,233**	**$122,714**

3.3 *Please recalculate Section H, Tab 2, page 2.2 assuming an inflation rate ("CPI") of 0 percent for each year, and provide a table similar to the response to the proceeding question for the several forecasts that shows the NGPiS increase and the capital addition for each year assuming a CPI change of 0 percent.*

Response

MID-YEAR NET GAS-PLANT-IN-SERVICE (NGPiS) AT 0% CPI
$000 NOMINAL

Line No.	Particulars	Decision 2003	Projected 2003	NGPiS Change	Forecast 2004	NGPiS Change	Forecast 2005	NGPiS Change	Forecast 2006	NGPiS Change	Forecast 2007	NGPiS Change	Forecast 2008	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**Mid-Year NGPiS**													
2														
3	Decision	$2,154,871	$2,148,959	$37,542	$2,186,501	$27,573	$2,214,074	$38,850	$2,252,924	$79,585	$2,332,509	$15,798	$2,348,307	
4														
5	Cost of Service	$2,154,871	$2,148,959	$38,027	$2,186,986	$28,500	$2,215,486	$39,750	$2,255,236	$80,493	$2,335,729	$16,702	$2,352,431	
6														
7	PBR Formula	$2,154,871	$2,148,959	$4,726	$2,153,685	$7,086	$2,160,771	$7,320	$2,168,091	$7,697	$2,175,788	$7,444	$2,183,232	
8														
9														
10					Plant		Plant		Plant		Plant		Plant	
11					Additions		Additions		Additions		Additions		Additions	
12	**Plant Additions Arising From:**				2004		2005		2006		2007		2008	
13														
14	**Decision**													
15	CPCN Additions				$9,687		$9,285		$22,259		$65,267		$6,857	$113,355
16	Regular Additions				108,060		107,374		111,137		106,047		105,017	537,635
17	Total Decision				$117,747		$116,659		$133,396		$171,314		$111,874	$650,990
18														
19	**Cost of Service**													
20	CPCN Additions				$9,687		$9,285		$22,259		$65,267		$6,857	$113,355
21	Regular Additions				109,029		108,283		112,092		107,013		106,009	542,426
22	Total Cost of Service				$118,716		$117,568		$134,351		$172,280		$112,866	$655,781
23														
24	**PBR Formula**				$58,754		$125,451		$63,373		$126,060		$62,888	$436,526

3.4 *Please repeat the foregoing question assuming a CPI increase of 6 percent for each year.*

Response

The following table provides the calculations for the three forecast scenarios based on an assumption of 6% CPI for each of the next 5 years. The effects of CPI changes on Capitalized Overhead have been left unchanged from the filing materials for this analysis.

It should be noted that the probability of CPI rising to 6% for each of the next five years is highly unlikely. This is evidenced by the current 5 Year Government of Canada Benchmark Bond Yield at approximately 3.75% and the 10 Year Bond Yield at approximately 4.5%. However, the analysis does show that extreme changes in CPI significantly affect the forecast plant additions determined through the PBR formula to levels well beyond what would have been allowed using cost of service methodology. The response to Question 3.5 discusses modifications that could be made to the PBR formula to accommodate extreme values for forecast CPI.

MID-YEAR NET GAS-PLANT-IN-SERVICE (NGPiS) AT 6% CPI
$000 NOMINAL

Line No.	Particulars	Decision 2003	Projected 2003	NGPiS Change	Forecast 2004	NGPiS Change	Forecast 2005	NGPiS Change	Forecast 2006	NGPiS Change	Forecast 2007	NGPiS Change	Forecast 2008	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**Mid-Year NGPiS**													
2														
3	Decision	$2,154,871	$2,148,959	$39,657	$2,188,616	$34,836	$2,223,452	$53,724	$2,277,176	$109,117	$2,386,293	$39,569	$2,425,862	
4														
5	Cost of Service	$2,154,871	$2,148,959	$40,141	$2,189,100	$35,765	$2,224,865	$54,624	$2,279,489	$110,024	$2,389,513	$40,473	$2,429,986	
6														
7	PBR Formula	$2,154,871	$2,148,959	$134,919	$2,283,878	$146,039	$2,429,917	$155,626	$2,585,543	$166,039	$2,751,582	$176,325	$2,927,907	
8														
9														
10					Plant		Plant		Plant		Plant		Plant	
11					Additions		Additions		Additions		Additions		Additions	
12	**Plant Additions Arising From:**				2004		2005		2006		2007		2008	
13														
14	**Decision**													
15	CPCN Additions				$9,641		$9,794		$24,956		$77,709		$9,176	$131,276
16	Regular Additions				112,380		116,658		126,637		125,956		130,246	611,877
17	Total Decision				$122,021		$126,452		$151,593		$203,665		$139,422	$743,153
18														
19	**Cost of Service**													
20	CPCN Additions				$9,641		$9,794		$24,956		$77,709		$9,176	$131,276
21	Regular Additions				113,349		117,567		127,592		126,922		131,238	616,668
22	Total Cost of Service				$122,990		$127,361		$152,548		$204,631		$140,414	$747,944
23														
24	**PBR Formula**				$324,106		$160,349		$361,264		$196,218		$398,613	$1,440,550

3.5 *Please discuss whether the proposed formula for NGPiS is robust and gives a reliable forecast of expected capital additions across a broad range of possible circumstances*.

Response

Terasen Gas believes that the proposed formula for total revenue requirements is robust over a reasonable range of inflation rate scenarios. When viewed by separate revenue requirement components (O&M and Net Gas-Plant-in-Service), the formula generally results in greater efficiency, challenges for O&M expenditures than for capital expenditures. Separate formulae or individual adjustment factors could be applied to each component of the controllable costs, however, Terasen Gas believes that an overall revenue requirement formula focused on total revenue requirement per customer for controllable costs is more consistent with a customer focused, outcomes-based PBR.

Terasen Gas believes that the PBR formula as proposed can be modified to accommodate extreme values in CPI outside of the range currently anticipated. In particular, floors and caps could be established for the forecast of CPI to be used for rate setting purposes to limit the effects of extreme values. In addition, the adjustment factor could be expressed as a percentage applied against forecast CPI rather than using a constant subtractive factor. For example, based on forecast CPI of 2%, the 0.75% adjustment factor is equivalent to a multiplicative adjustment factor of: (2% - 0.75%) / 2% = 0.625

Therefore, each year, formula based costs would be determined by multiplying O&M and Net Gas-Plant-in-Service per customer by forecast CPI x 0.625. Therefore, in periods of higher inflation, the adjustment factor would be greater than 0.75% and in periods of lower inflation, the effective adjustment factor would be less than 0.75%. This approach would moderate swings in formula based costs at extreme values but yield substantially similar results as the formula proposed in the Application.

4.0 Reference: Application, Tab D, Section H, Tab 3
BC Gas Utility Ltd. Decision dated February 4, 2003

4.1 *The Commission's Decision on 2003 Revenue Requirements approved a regular capital additions budget for Categories A, B and C of $85.846 million. Further to the discussion on page D-1 of the Application, please separate this amount into the portion for which Terasen Gas considers customer additions is the key driver, and Other. Please identify how Categories A, B and C items were grouped to arrive at the result*.

Response

Set out below is the portion of the Capital Categories A, B and C considered to be customer driven. Also provided is a subtotal for the Other capital that reconciles to the total regular capital additions for Categories A, B and C.

TOTAL CAPITAL Categories A, B & C
($000)

	Decision 2003
Customer additions driven capital	
A: Mains	$6,000
A: Services	10,577
A: New Meters (prorata customer additions)	2,815
Customer addition driven capital	**19,392**
Other capital	
A: Meters (prorata meter exchange activities) & Evergreen program	14,068
B: System Integrity and Reliability	25,386
C: New Stations, Main & service renewals/alterations	27,000
Total other capital	**66,454**
Total regular capital additions (Categories A, B & C)	**$85,846**
A: Mains, Services, Meters	$33,460
B: System Integrity and Reliability	25,386
C: All Other Plant	27,000
Categories A, B & C	**$85,846**

4.2 *Please calculate the customer additions driven component of regular capital additions from the 2003 Decision on a per customer added basis. Then, use a formula similar to that proposed for the 2004/08 PBR (i.e., 1 + CPI – 0.75) and the forecast of customer additions to estimate the additions driven component of regular capital additions for the 2004 through 2008 period*.

Response

The required calculations are shown below.

	Decision 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Customer driven capital per customer addition	$2,093	$2,115	$2,141	$2,168	$2,195	$2,222
Number of customers additions		8,459	8,521	8,793	8,864	8,952
Customer addition driven capital ($'000)		**$ 17,891**	**$ 18,243**	**$ 19,063**	**$ 19,456**	**$ 19,891**

4.3 *Turning to the Other regular capital additions amount from the first question in this section, please calculate the Other additions per customer. Then, use a formula similar to that proposed for the 2004/08 PBR [i.e., (1 + CPI - 0.75)] to estimate the amount of Other regular capital additions per customer and the total number of customers to calculate Other capital additions for the period 2004 through 2008*.

Response

Please see table below.

	Decision 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Total other capital additions per customer	$86	$87	$88	$89	$90	$91
Average number of customers		783,070	791,584	800,267	809,177	818,082
Total other capital ($'000)		**$68,127**	**$69,659**	**$71,224**	**$72,826**	**$74,445**

4.4 *Further to pages D-27 through D-32, please provide a table summarizing by year, forecast CPCN expenditures in nominal dollars for 2004 through 2008. If the cost of the Transmission Operations Compliance Strategy or the AM/FM GIS system for Transmission is included, please explain*.

Response

Please see table below:

CPCN EXPENDITURES (Including AFUDC)
($000)

Proposed CPCNs	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2007
Transmission Pipeline Integrity Plan	$9,412	$10,448	$4,667	$4,675	$4,766
Nichol to Coquitlam Loop		12,735	11,155		
Naramata Loop			32,963		
Kitchener B Compressor Unit Addition			19,858		
TOTAL COSTS - CPCNs	**$9,412**	**$23,183**	**$68,643**	**$4,675**	**$4,766**

The AM/FM GIS system for transmission is estimated to cost $2 million. The costs have been included in the Category C capital forecast.

4.5 *Recognizing the higher level of regulatory oversight for CPCN projects, the "lumpiness" of such projects and the relatively small amount of such work proposed for 2004 through 2008, please discuss why Terasen Gas proposes to include CPCN expenditures in the PBR incentive mechanism for 2004/08. What are the pros and cons of including these expenditures in the incentive mechanism*?

Response

The proposal to include CPCNs in the PBR incentive agreement responds to requests from customer representatives to see a more comprehensive treatment of capital expenditures particularly in the context of a longer term PBR Plan. Terasen Gas believes that including all capital expenditures in the incentive agreement is more consistent with a results based approach to PBR than segmenting certain elements of capital expenditure.

The advantages of this approach are that customers are given greater certainty as to the level of capital costs that are reflected in revenue requirements and the Company is provided incentives to achieve further efficiencies in all aspects of capital spending. The Commission's review and approval process for CPCN projects would continue throughout the term of the PBR Plan.

The disadvantage to the Company of the inclusion of CPCNs in the incentive is that the Company is exposed to greater risk for managing CPCN related costs. Terasen Gas does not foresee any disadvantages to customers associated with the inclusion of CPCNs in the incentive.

4.6 *Based on the foregoing calculations, please provide a table that summarizes by year for 2004/08 the customer addition driven regular capital additions, the Other regular capital additions and the forecast CPCN additions. Also, please show the total regular capital additions and the total including CPCNs*.

Response

	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Customer addition driven capital calculated per IR 1 Q 4.2	$17,891	$18,243	$19,063	$19,456	$19,891
Total other capital additions calculated per IR 1 Q 4.3	68,127	69,659	71,224	72,826	74,445
Total regular capital additions	**86,018**	**87,902**	**90,287**	**92,282**	**94,336**
CPCN forecast	9,412	23,183	68,643	4,675	4,766
Total regular capital additions including forecast CPCN addtions	**$95,430**	**$111,085**	**$158,930**	**$96,957**	**$99,102**

4.7 *Please repeat the calculation to calculate regular capital additions for 2004 through 2008 as set out in the earlier portions in this section using a CPI change of 6 percent per year, and provide a similar table based on CPI increases of 6 percent per year*.

Response

The table below set out the results for regular capital additions using a CPI change of 6% per year based on the same formula as requested in questions 4.2 and 4.3. Although the table below reflects the result of applying a 6% inflation factor, it should be noted that the current BC Ministry of Finance forecast of inflation for 2003 and 2004 is approximately 2.0%. It is highly unlikely that over the forecast period the sustained level of inflation in the economy would reach 6% per year for the full five-year period. Further, the base forecasts in the application assumed 2% inflation and if actual inflation were higher then these comparative costs should be adjusted accordingly.

	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Customer addition driven capital per formula (1+CPI 6 -.0.75)	$18,635	$19,760	$21,464	$22,772	$24,206
Total other capital additions per formula (1+CPI 6 -.0.75)	$71,259	75,992	80,827	85,773	91,625
Total regular capital additions per formula (1 + CPI 6 - 0.75)	**$89,894**	**95,752**	**102,291**	**108,545**	**115,831**
CPCN forecast	$9,412	23,183	68,643	4,675	4,766
Total regular capital additions & forecast CPCN's	**$99,306**	**$118,935**	**$170,934**	**$113,220**	**$120,597**

5.0 Reference: Application, Tab D, pp. D-5 to D-32

5.1 *Recognizing that Category B expenditures tend to be relatively variable, please briefly explain why Distribution Plant expenditures as shown on page D-14 are expected to decrease for 2007 and 2008.*

Response

The forecast levels of Distribution Category B expenditures for 2007 and 2008 of $9 million are similar to 2001-2002 expenditure levels. Inclusion of two larger system improvement projects in 2003 (Kootenay Loop $3 million) and 2006 (Fraser Loop $5 million) move these particular years away from the norm. No larger system improvements have yet been identified for 2007 and 2008 from our planning methodology. The later years in any forecast tend to be less certain.

5.2 *Page D-25 shows Total Nominal Category C IT expenditures of $17.8 million in 2007 and $18.2 million in 2008. Please briefly explain why a Decision Impact amount of $3.2 million is shown for 2007, and not for 2008. Is it a coincidence that omitting a Decision Impact amount for 2008 does not cause a material change to the trend for Category C IT expenditures?*

Response

When the Company prepared the Category C IT expenditure forecast table in the Application, it updated the corresponding table included in the 2003 revenue requirements application which did not include 2008. In order to facilitate the comparison of the information with the previous application, a line was added to reflect the impact of the February 2003 Decision on the previously forecast information.

In order to add the final year 2008 to the forecast included in the Application, the forecast amount for 2008 was the result of adding inflation to net amount forecast for 2007 after reducing for the Decision impact. Therefore, the 2008 forecast does take into account the $3 million reduction identified in 2003 and is not simply a coincidence.

5.3 *Pages D-29 and D-30 state that a 24 km pipeline loop in the Okanagan costing $33 million and a third compressor unit at the Kitchener B Station costing $19.9 million are expected to be needed in 2006.*

In the Load Planning Methodology Report filed June 28, 2002, Terasen Gas recognized it needed to improve planning procedures for the Interior Transmission System ("ITS"). Please provide a brief progress report on the improvements to procedures for the ITS, and clarify whether the timing of the looping and additional compressor have been re-evaluated and confirmed using the improved procedures. If the 2006 upgrades have not been re-evaluated using the improved procedures, when will such a reassessment be completed?

Response

Improvements to the planning procedures at Terasen Gas are ongoing. Over the past several months, Terasen Gas has:

- Harmonized load forecasting methodologies for both Distribution and Transmission systems, which are in turn used for capital planning of the Interior Transmission system ("ITS"). Peak day load estimates are derived from peak hour load forecasts at Gate Station level, provided to Transmission Planners by Distribution System Planning;
- Migrated to the use of most up-to-date Gate Station Flow and Customer Use Rate Data available from Distribution System Planning models;
- The ITS hydraulic model has been rebuilt with increased physical and geographical accuracy. A verification process to check the model simulation accuracy against actual Winter 2002/03 flow data is currently being undertaken and is scheduled for completion in early fall;

Terasen Gas intends, as part of its annual capital planning cycle, to review the forecasted timing of required capital items, including the Okanagan Reinforcement project looping and additional compression referenced above, in September/October, 2003. At the present time, Terasen Gas is not aware of any material changes in the timing for the referenced additional compressor unit and pipeline loop.

5.4 *Page D-31 anticipates that the Nichol-Coquitlam loop will be built in 2005 and 2006 at a cost of $23.8 million. Please outline the minimal set or sets of circumstance that will need to occur for the loop to be needed by 2006. Under what circumstances would the change not need to be built until 2008 or later*?

Response

The anticipated timing of the Nichol-Coquitlam loop is based on the forecast Lower Mainland core and firm transportation peak hour flow requirements of 1,896 10^3m^3/hour and 1925 10^3m^3/hour occurring in 2005 and 2006 respectively. This peak hour volume includes Lower Mainland core customer demand, plus contracted volumes under the BC Hydro Bypass Transportation Agreement and the Terasen Gas (Vancouver Island) Wheeling Agreement.

Deferral of the loop could result from a reduction of Lower Mainland peak hour core customer demand, or changes in obligations under either the BC Hydro Bypass Transportation Agreement or the Terasen Gas (Vancouver Island) Wheeling Agreements. Terasen Gas is not aware of any contemplated changes to the latter two factors.

6.0 Reference: E-44 and E-48

6.1 *Terasen Gas's current insurance contracts renew in November 2003. Insurance premium increases of $2.1 million in basic and umbrella coverage are forecast for 2004 along with additional 10 percent increases per year from 2005 to 2008. Variances in insurance costs are to be captured in a deferral account.*

With the anticipated increase in insurance and the proposed true up transferring the risk to customers, what process has Terasen Gas undertaken or is planning to undertake to limit the increase in insurance expenses? Has Terasen Gas solicited quotes from insurance providers? Has an assessment been done of the coverage offered, the premiums charged and the likelihood of claim to determine an appropriate level of insurance? Has some portion of self-insurance been considered for the Terasen group of companies?

Response

Insurance increases are estimated for the period for 2004 to be $2.1 million and for 2005-2008 to increase by 10% per year. The large increase for 2004 relates to the expiry of the three year arrangement for the Excess Package underwritten with Lloyd's. This coverage relates to Property, Business Interruption (BI) and Liability to a limit of $150 million in excess of $5 million for liability and in excess of $10 million for Property/Business Interruption. This three-year arrangement was placed previous to the "hard" market conditions that all buyers are currently experiencing and has bestowed a very material financial benefit to the Company and its customers since the hardening of the market in late 2001.

The present expectation as assessed by Terasen's insurance brokers is that Terasen will see an increase in premiums of about 300% when it replaces this coverage in the marketplace in the autumn. Terasen will aggressively market the entire program for the Nov. 30, 2003 renewal and the review of coverage will include a market review of required limits, self insured retentions (deductible levels) and all available markets. This process has currently commenced but will not be fully completed until late Nov / 2003. The review process is carried out with Terasen's broker Jardine Lloyd Thompson and is conducted in the context of ever-changing market conditions. The Terasen profile is reasonably attractive to underwriters in today's market and Terasen believes it will continue to be so in future years hence there should be significant vendor interest.

Terasen Gas has done an assessment of the coverage sought. It has reviewed its insurable limits by benchmarking against other comparable organizations. It has also completed a Maximum Foreseeable Loss study and it is currently in the process of completing a full Business Interruption/Contingent Business Interruption study. With this information Terasen is able to estimate required limits of coverage. For Terasen Gas, first and foremost is the exposure to earthquake on the Property/Business Interruption side of the equation. The studies indicate that this exposure is currently greater than the limits carried by Terasen Gas. The largest exposure with respect to Liability relates to an explosion in a densely populated building. The studies indicate that coverage for this exposure is likely to be adequate at present levels.

The forecast of insurance costs for the five-year period are based on the market conditions at the time of the forecast. The information was provided in consultation with Jardine Lloyd Thompson who is a world-wide brokerage firm specializing in the energy industry. Unlike some arrangements with insurance brokers, Terasen's arrangements with Jardine do not provide greater consideration to Jardine for larger premium placement, instead the consideration is related to time and effort. Potential costs of insurance in the future are speculative. Markets can change at any time in response to a number of factors including insurers loss ratios, availability of capacity and prevailing investment conditions. In the present environment, one-year estimations are the best Terasen can reasonably do without a hedge of some sort. Even with the estimated 10% increase year-over-year the variance may be much greater. It is Jardine's belief that the insurance market will not revert to premium levels of previous years. The "soft" market of previous years related to exceptional investment returns from the financial markets and an overabundance of capacity. This is not the case today. Instead the insurance industry is now much more focused on realizing an underwriting profit without undue reliance on investment returns from financial markets.

Terasen has dramatically increased its self insurance over the past year or two through the assumption of much higher deductibles than in the past. For example, Terasen's deductible for property claims went from $25,000 to $250,000 in November, 2002. This trend is likely to continue as many organizations and insurers see even higher deductibles for certain areas of coverage in the future. Terasen will be assessing the appropriate new deductible levels in the marketplace as November 30, 2003 approaches. Terasen has also done a preliminary review of Alternative Risk Transfer methods to finance exposures, sometimes referred to as captives. The initial conclusions are that these approaches are not very efficient in Terasen's circumstances but may have application should underwriters begin to view Terasen's profile harshly.

6.2 Reference: E-4

Based on the Terasen Gas forecast of customer growth, please calculate the O&M per year assuming the 2003 Decision net O&M of $149,294,000 increased by two percent inflation, customer growth and PIFs at 1 percent, 1.25 percent and 1.5 percent.

Response

The Net O&M results of the above scenarios are displayed in the table below.

NET O&M
BASED ON FORECAST CUSTOMER GROWTH
($000)

Line No.	Particulars	Decision 2003	2004	2005	2006	2007	2008
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CPI = 2%, PIF = 1%	$149,294	$152,199	$155,328	$158,537	$161,839	$165,192
2							
3	CPI = 2%, PIF = 1.25%	$149,294	$151,830	$154,575	$157,386	$160,275	$163,195
4							
5	CPI = 2%, PIF = 1.50%	$149,294	$151,461	$153,823	$156,239	$158,718	$161,217

6.3 Reference: E-6

Why does Terasen Gas not require executive and other employees to contribute towards the cost of their pensions? Please identify other B.C. companies outside of the utility or telecommunications industries which provide free pensions.

Response

In determining the level of pension benefits provided to employees, Terasen Gas, like most employers, assesses the competitive value of the overall total compensation package. In assessing the values of pension and benefits programs, reference is made to the employer-provided value, i.e. after deducting any employee contributions.

The Company's external pension actuary indicates that, in general, the majority of defined benefit pension plans provided by private sector employers in Canada are non-contributory. The general rate of pension accrual in a B.C. sample is 2% of pensionable earnings, the same as Terasen Gas. More generally, broad industry practice is to provide a rate of pension accrual for executives of 2%, as does Terasen Gas.

Of all the companies in the Company's external consultant's data bank who sponsor defined benefit pension plans, over 60% are non-contributory. For B.C. companies, the proportion sponsoring non-contributory pension plans is just over 50%. The actuary indicated that the following companies outside the utility and telecommunications industries provide non-contributory pensions for at least some employees:

- Canada Malting Co. Ltd.
- Celgar Pulp Co.
- Chemetics, a Division of Aker-Kvaerner Canada Inc.
- Finning Canada
- HSBC Bank Canada
- Methanex Corp.
- NorskeCanada

- Placer Dome Inc.
- Teck Cominco Metals Ltd.
- TimberWest Forest Corp.
- Weyerhaeuser Canada Ltd.

7.0 Demand Side Management
Reference: Tab G, p. G-6

7.1 Please explain the criteria that will be employed in determining which programs will be included in the DSM incentive?

Response

A continuation of the DSM incentive grants deferral account (for deferral of customer incentives to a maximum of $1.5 million per year) is requested to encourage customers to adopt certain DSM measures. Examples of customer incentives offered by the utility in recent years include the commercial sector Efficient Boiler grants (varying dollar value depending on the type and size of boiler installed) and the residential sector rebates for the purchase of weatherization products ($25.00), heating system tune-ups ($25.00) and heating system upgrades ($150.00).

Customer incentives would be offered to improve take-up rates on programs by reducing financial barrier to purchasing. Incentive payments or rebates would only be provided where the amount of incentive available from the utility (perhaps in combination with other sources such as government or equipment suppliers) is expected to have a reasonable market impact. The portfolio of prospective programs offered by the utility in any year would be expected to have a positive Total Resource Cost test result based on total projected costs and benefits. In addition, prospective programs would be expected to have a Ratepayer Impact Measure test result that compares favourably with other similar programs. These benefit-cost tests have been used for DSM program selection and ranking by the Company since the mid-1990's.

7.2 *Please explain if customer awareness programs will be included in the DSM incentive or would these programs be treated as advertising expense*?

Response

The deferral account for customer incentives would only be used to collect incentive payments and rebates made to customers. Costs associated with advertising (including awareness programs), program promotion, program design, administration, research and evaluation would continue to be treated as O&M expenses.

8.0 Reference: Application, Section H, Tab 3, pp. 6.7, 6.8, 6.20; Tab 12, pp. 1, 2

8.1 *NGV Conversion Grants were $141,000 in 2002 and are forecast to be $725,000 in 2004. Please confirm that the information on pages 6.7 and 6.8 of Tab 3 will be updated for the 2003 Annual Review.*

Response

The Company confirms that the information on these pages will be updated for the 2003 Annual Review.

8.2 *For the SCP deferral accounts shown on Lines 50, 57 and 58 of page 6.20 of Tab 3, please show how the forecast gross additions for 2003 were estimated.*

Response

The table below shows the calculations of the forecast gross additions in 2003 for the SCP deferral accounts.

2003 SCP DEFERRAL ADDITIONS
$000

SCP Net Mitigation Revenues	
Spot Revenues included in Test Year	$1,300
Less: Projected Spot Revenues	(238)
Total Deferral Additions (Sec H, Tab 3, Pg 6.20, Line 56)	$1,062
SCP PG&E Contract Cancellation	
PG&E - SCP Third Party Firm Revenues in Test Year	$3,600
Less: Projected Mitigation Revenues using PG&E Capacity	(2,200)
Total Deferral Additions (Sec H, Tab 3, Pg 6.20, Line 58)	$1,400

8.3 *Page 1 of Tab 12, Section H reports $7.8 million of firm SCP revenue and $1 million of spot SCP revenue in 2004. Page 6.7 of Tab 3 shows additions to SCP deferral account debit balances of $775,000 and $3,000,000. Please explain how these numbers were arrived at.*

Response

The table below shows the calculations of the forecast gross additions in 2004 for the SCP deferral accounts. The table also includes the details of the Forecast 2004 SCP Third Party Revenues.

2004 SCP DEFERRAL ADDITIONS
$000

SCP Net Mitigation Revenues	
Spot Revenues included in Forecast Revenue Requirement (Sec H, Tab 12, Page 1)	$1,000
Less: Forecast Spot Revenues	(225)
Total Deferral Additions (Sec H, Tab 3, Pg 6.8, Line 56)	$775
SCP PG&E Contract Cancellation	
PG&E - SCP Third Party Firm Revenues in Revenue Requirement	$3,000
Less: Forecast Mitigation Revenues using PG&E Capacity	0
Total Deferral Additions (Sec H, Tab 3, Pg 6.8, Line 58)	$3,000
Forecast 2004 SCP Third Party Revenues	
PG&E Revenues (Jan 1 to Oct 31, 2004) [BCUC Letter No. L-48-02]	$3,000
Replacement Contract (Nov 1 to Dec 31, 2004)	1,220
B.C. Hydro Firm Contract	3,600
Subtotal	7,820
Spot Revenues	1,000
Total (Sec H, Tab 12, Page 2, Line 7, Col 4)	$8,820

8.4 *Why not forecast the amount of SCP third party revenue in 2004 that would result in zero forecast additions to the SCP deferral account balances in 2004*?

Response

The rationale for forecasting deferral accumulation in 2004 in the SCP third party revenue account is described in detail on Page F-12 of the application. In general terms the forecast is based on the treatment set out in BCUC Letter No. L-48-02 for lost revenues from the PG&E contract cancellation. Letter No. L-48-02 prescribes deferring until November 1, 2004 the lost PG&E revenues net of any mitigation achieved.

8.5 *What is gained by showing three SCP deferral account balances (four accounts if the Deferred 2000 SCP Cost of Service account on Line 55 is included)? What would be lost if only one SCP deferral account were shown*?

Responses

The multiple accounts were established initially to deal with different categories of SCP mitigation. These categories can also be tracked separately within a single account. The distinction between these categories would be lost if the line items were reduced to a single account. If it is considered preferable to display only one SCP 3rd Party account, that can be accommodated.

9.0 Number of Customers

9.1 *Do the formulas reset for the actual number of customers each year during the PBR? For example, in setting 2005 O&M does the forecast average number of customers in 2005 recognize the actual 2004 opening customer count*?

Response

Yes. In the same manner employed in the 1998 – 2001 PBR, the customer growth factors will be updated for known actual results in the next Annual Review after a year is complete.

10.0 Inflation

10.1 *Is inflation reforecast each year at the Annual Review for the upcoming year or is the 1.8 percent CPI (BC) for 2004 and the 2 percent CPI (BC) for 2005 to 2008 fixed for all five years of the PBR*?

Response

Inflation is forecast each year for the upcoming year throughout the term of the PBR.

10.2 *At the Workshop, an issue was raised about whether a composite inflation rate of CPI (BC) should be used. The Bank of Canada website states that CPI Canada is based on the retail price of a representative shopping basket of about 600 goods and services from an average household's expenditure: food, housing, transportation, furniture, clothing, and recreation. The Bank of Canada also refers to Core CPI that excludes the eight most volatile items.*

For Terasen Gas, why is CPI (BC) an appropriate indicator of inflation in utility costs? Should Core CPI (BC) be used to remove the most volatile cost items? Are there inflation indicators that more closely track utility or commercial cost increases and if so why are they not proposed by Terasen Gas? How does the

0.75 percent adjustment factor proposed in the Application offset the volatile cost items in CPI (BC)?

Response

CPI (B.C.) is a reasonable benchmark for the determination of rates under the proposed PBR. The use of CPI (B.C.) is appropriate as this index has been used for the setting of the rates of Terasen Gas since 1994 and has proven to be a measure that has been workable without any noticeable difficulties arising from unintended results. While certain items included in CPI (B.C.) may be volatile, the overall index itself is not generally volatile. Independent forecast sources are readily available and accessible in a timeframe that fits with the rate setting process and they have not shown a wide variation from actual results. The CPI measure is also generally understood by parties and has meaning to customers.

By limiting increases in the revenue requirements per customer to be less than CPI (B.C.), customers are assured that these costs will decrease in real terms relative to other components of their household spending. Linking allowed controllable spending to indices that are disconnected from costs faced by customers moves away from the desire to implement customer focused, results based rates. Note that CPI (B.C.) or some other measure of inflation is not being used to forecast costs – the intent is to find a formula that relates revenue requirements to measures that are meaningful to customers.

11.0 Financial Schedules
Reference: Schedule H, Tab 9, pp. 2-3

11.1 *On line 21 the Total Items Not Subject to Overheads are shown as $19,373,000 for each year from 2003 to 2008 which includes amounts for vehicle lease and Fort Nelson. However on lines 28 and 29, the amounts for vehicle lease and Fort Nelson are increasing each year from 2004 to 2008. Please explain if an adjustment is required to this schedule and if so provide a revised schedule. Please explain why the amounts for vehicle lease and Fort Nelson for 2004 to 2008 are different on lines 22 and 23 of page 3 compared to page 2*.

Response

The $19,373,000 was allowed as a deduction in the determination of overheads capitalized in the 2003 Decision. For the 2004 to 2008 period, this amount was kept constant to minimize the amount of effort required to track it going forward as the difference between inflated and non-inflated numbers is relatively minor. If the Commission finds it appropriate to update, a revised schedule can be provided.

The amounts for vehicle lease and Fort Nelson for 2004 to 2008 are different on lines 22 and 23 of Page 3 compared to lines 28 and 29 of Page 2 because amounts on Page 3 have been inflated by CPI whereas Page 2 amounts have been inflated by growth in customers, CPI and an adjustment factor.

At the Workshop, the vehicle and coastal facilities leases were identified as being updated or forecast at the Annual Review. Since the vehicle lease amount is used in the calculation of capitalized overhead and net O&M, will this updated annual forecast be reflected in the capitalized overhead and net O&M calculation for 2004 to 2008?

Response

The vehicle lease amounts used in the net O&M calculation (Section H, Tab 9, Page 2, Line 29) already reflects the latest update as discussed at the Workshop. As whether these amounts should be inflated under the section "not subject to overheads" the Company does not believe the impact is material but is willing to incorporate such changes if so required.

11.2 *At the Workshop Terasen Gas stated that even though the Application proposes to update the cash working capital component of rate base at the Annual Review, this component could be calculated by a formula. Please provide a formula for cash working capital that could be used for 2004 to 2008*.

Response

One simple formulaic method that could be used to calculate cash working capital is to apply a factor to Net Gas-Plant-in-Service Mid-Year. This method is consistent with the formula calculation of Net Gas-Plant-in-Service and produces the following results:

Line No.	Particulars	2004	2005	2006	2007	2008	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Net Plant in Service Mid-Year	$ 2,192,745	$ 2,244,291	$ 2,297,270	$ 2,351,881	$ 2,407,484	
2							
3	Factor	-0.85%	-0.85%	-0.85%	-0.85%	-0.85%	
4							
5	Cash Working Capital	$ (18,638)	$ (19,076)	$ (19,527)	$ (19,991)	$ (20,464)	$ (97,696)
6					-		
7	Cash Working Capital per Application	$ (19,196)	$ (19,103)	$ (19,482)	$ (19,797)	$ (19,747)	$ (97,325)

11.3 *Page 3, line 40 shows the decision based total gross O&M requirements from 2004 to 2008. Please itemize these additions by year and show the basis of calculation*.

Response

The additional gross O&M requirements over and above the Decision based levels are as follows:

Line No.	Particulars	2004	2005	2006	2007	2008
1	CustomerWorks Contract Correction / Renewals	$ 764	$ 763	$ 986	$ 988	$ 988
2	Gas Supply Application to Replace Gas Connect	235	240	245	250	255
3	External Health & Safety Audit	20	(21)	(21)	(22)	(22)
4	Environmental Consulting & Reporting	31	31	32	32	33
5	Increases due to Higher Commodity Costs:					
6	Line Heater Fuel	583	595	607	619	631
7	Compressor & LNG Fuel	333	340	346	353	360
8	Bad Debt	2,061	1,538	1,472	1,375	1,435
9	Incentive Compensation	1,648	1,701	1,757	1,813	1,872
10	Pensionable Bonuses	258	266	274	283	293
11	SAP License Renewal & Compliance	127	130	132	135	138
12	Content Management Licensing		103	105	108	109
13	Server Support			30	32	32
14	Radio Licenses				71	72
15	Facilities Maintenance	1	1	1	2	2
16	Total per Section H, Tab 9, Page 3, Line 40	$ 6,061	$ 5,687	$ 5,966	$ 6,039	$ 6,198

The amounts included above are Terasen Gas' best current estimates of the incremental costs it would advance evidence for in a rate case proceeding should a PBR settlement not be reached. Additional costs may also be identified over the ensuing period.

12.0 2002 Annual Report to the Commission

12.1 *Letter No. L-15-03 approved an extension to the filing of the 2002 Annual Report to May 31, 2003. As indicated in L-15-03, please file with the Commission a full copy of the Annual Report*.

Response

The Company's 2002 BCUC Annual Report was filed with Commission on May 29, 2003.

12.2 *Pages 8.1 and 9 of the Annual Report identify 2002 opening adjustments of $21,146,000 to gas plant in service and accumulated depreciation for the transfer of CustomerWorks assets. Please reconcile the adjustments to gas plant in service and accumulated depreciation to the book value adjustment that was anticipated in Commission Order No. G-29-02 for the transfer of CustomerWorks assets.*

Response

Please see table below for the reconciliation to gas plant in service and accumulated depreciation to the book value adjustment that was anticipated in Commission Order No. G-29-02 for the transfer of CustomerWorks assets.

	($000)
Fair Value for Assets (BCUC Order G-29-02, Page 13)	$39,204
Fair Value for Asset Adjustment/True-up (Clause 5 of the CustomerWorks Asset Transfer Agreement)	70
Add: Accumulated Depreciation	3,755
Gross Plant	43,029
Less: Work-in-progress	(21,883)
2002 Opening Adjustments to GPIS, (Page 8.1 and 9)	$21,146

12.3 *On page 1-14-02 of the 2002 Revenue Requirements Application an average 2002 unfunded debt cost of 6.5 percent and long term debt cost of 7.805 percent was forecast. On Schedule IV, page 45 of the 2002 Annual Report the actual average cost of unfunded debt is shown as 2.9 percent and for long term debt is shown as 7.795 percent*.

When Terasen Gas proposed the withdrawal of its 2002 Revenue Requirements Application, it does not appear that the Utility's withdrawal filings or Commission Order No. G-123-01 addressed the interest deferral account activity. Page 13 of the Annual Report shows no 2002 activity in the interest deferral account, please explain how this treatment is consistent with the approval of Order G-123-01.

Response

BCUC Order No. 123-01 and the Reasons for Decision acknowledged that with the withdrawal of the 2002 Application there were a number of cost increases that the Company would have to absorb and a number of other items that were decreasing that were available to the Company to meet the challenge presented by the increasing items. For example, the Company would not be requesting an increase for significant plant additions but the benefit of expected tax rate decreases were to the Company's account to enable it to meet these challenges.

With respect to interest expense, in particular, the formal application of August 24, 2001 requested that an interest deferral account for long term and unfunded debt interest be in effect in 2002. The application further requested that a projected credit balance at the end of 2001 of $3.4 million be amortized over three years commencing January 1, 2002. (The actual 12/31/2001 deferred interest balance was a credit of $4.077 million, about $0.7 million greater than the amount projected in the withdrawn application.) It was the Company's belief that the deferral account would not continue without an order from the Commission for its continuance and further that there was no approval to amortize any of the credit balance in 2002. Therefore the Company's 2002 results reflect the actual interest expense and no additions were made to the deferred interest account, but also none of the $4.077 million credit balance was taken into income in 2002. Amortization of the $4.077 million in rates was applied for again and approved in conjunction with the Company's 2003 revenue requirement application.

A further indication that actual interest expense was being recorded in the Company's 2002 results was evident in the response last summer to BCUC Staff Information Request No. 1 dated July 15, 2002. Page 4 of Appendix 4 and Page 4 of Appendix 5 of that response show projected ROE of 9.52% (in contrast to the allowed of 9.13%) and show the cost of unfunded debt to be 3.2% (in contrast to the 5% for 2003).

While the Company expected some positive variances in interest expense, which with the benefit of hindsight became significant, the amount was uncertain at the time of withdrawing the 2002 Application. Beyond that, the 2002 interest expense savings had to exceed the amortization not taken of one third of the 2001 deferred interest balance before interest savings would provide a contribution to meeting the revenue requirement challenge identified in the withdrawal documentation.

Please explain how Terasen Gas was able to obtain 2002 average unfunded debt financing of about $145 million at 2.9 percent. Was this financing through intercompany loans?

Response

Terasen Gas' unfunded debt financing in 2002 was obtained primarily through borrowings in the Canadian commercial paper market. The difference between actual rates and the rate forecast in the 2002 Revenue Requirements application reflected the significant decline in Canadian short-term interest rates.

The unfunded debt for 2004 is forecast at 4 percent and for 2005 to 2008 is forecast at 5 percent on Schedule H, Tab 14 of the PBR Application for average debt amounts ranging from about $145 million to $195 million. Please explain if the same sources of unfunded debt financing utilized in 2002 will be used in 2004 to 2008 and if those expected debt costs have been reflected in the forecast.

Response

The Company anticipates that it will continue to access the Canadian commercial paper market for its unfunded borrowing requirements, and has based its forecast of unfunded debt costs on commercial paper borrowing rates. Since June 2002, Canadian short-term interest rates have been steadily increasing from the historically low levels experienced in early 2002. The Company expects this trend to continue through 2003 and 2004.

13.0 Increases in Delivery Margin

13.1 *In its letter dated May 22, 2003 to Commission Order No. G-38-03, the Commission panel requested that the settlement negotiations explore ways to manage increases in the total delivery margin cost so as not to outpace the CPI (BC) or similar indicator. What proposals does Terasen Gas consider are available to manage increases in the total delivery margin cost*?

Response

Terasen Gas believes that PBR is the most effective regulatory model for ensuring that total delivery margin costs are as low as possible. The proposed PBR incorporates a formula that limits increases in rates associated with those costs over which the Company has the greatest control to increases below inflation. Furthermore, the formula provides incentives to encourage the Company to achieve further productivity gains that will be shared with customers and thereby further reducing rates. The comprehensive treatment of all capital spending also ensures that rates will not increase due to capital spending on CPCNs or other capital projects.

Another important feature of the proposed PBR that is intended to help limit increases in total delivery costs to less than inflation is the proposed revenue incentive. Terasen Gas' Application pursues the need for load building to spread the total delivery cost over a greater throughput. Increased opportunities to generate new load and additional revenues are important for offsetting declines in use per customer and cost pressures.

These initiatives will ensure total delivery costs will be limited to increases less than inflation subject to changes in the flow-through costs – or items over which the Company has less control. The proposed PBR Plan does not include these items in the formula and therefore variances in these items could result in either increases or decreases in total delivery rates. One might realistically hope that the impact of limiting controllable expenses to CPI – 0.75% would more than offset any upward cost from uncontrollable expenses so that the weighted average impact over the five-year period would be below the five-year CPI (B.C.) but this is not certain.

The major step forward in the Application relative to earlier PBR models is the expansion of the definition of controllable expenses to include all expenditures on gas plant including all CPCNs. By including all such expenditures as controllable expenses the Company has eliminated one of the major areas of pressure pushing rates beyond CPI (B.C.).

Terasen Gas can achieve this outcome by putting in place a multi-year PBR Plan that enables the payback of upfront investments in long term efficiencies. It is less clear to Terasen Gas how to keep the rate impact of changes in uncontrollable costs to CPI (B.C.) or less.

During the April 15, 2003 Workshop, some parties expressed concern about the potential rate pressure from uncontrollable costs such as property taxes. Terasen Gas was requested to propose incentives around expense items of this type to give greater comfort that these areas were being actively managed with the hope that upward rate pressures would be ameliorated. Terasen Gas supports investigating options for establishing positive incentives on some of these items to further enhance the alignment between the Company and customers towards keeping increases in the delivery margin at a level that does not outpace inflation.

Because of the unpredictable and often volatile nature of the flow through costs and the limited level of control available to the Company over these costs, it would not be possible to include flow through items within the PBR formula without changing the Company's risk profile. Terasen Gas believes that it would be inappropriate to expose the Company to the increased risk associated with managing these costs without providing for a higher risk premium under the Commission's ROE adjustment mechanism and potentially other changes to the PBR Plan.

Terasen Gas believes that the proposed Plan strikes a reasonable balance between establishing incentives to reduce the costs over which it has the greatest control and flowing through both positive and negative variances without materially changing the Company's risk profile.

Terasen Gas believes that proposals for limiting total delivery rate increases including positive incentives for items such as property taxes and revenue and load growth incentives can be considered in the context of the overall PBR Plan through the NSP.

14.0 Rate Changes During the PBR

14.1 *Please describe how rates will be reset during 2004 to 2008 in conjunction with the Annual Review and whether flowthrough and sharing adjustments will be made on an annual basis utilizing forecast or actual amounts*.

Please explain if Terasen gas will be filing projected results for the sharing mechanism and forecasts for the upcoming year along with revised targets in advance of the Annual Review.

Response

It is proposed that rates will be reset same way as they were during the 1998 – 2001 PBR. Flow-through and sharing adjustments will be made on an annual basis. Also, projected results will be filed for the setting of rates for earnings sharing and other incentives as appropriate. There will be a true-up to actual earnings sharing and incentive amounts after the full year is complete which will affect rates in the following year.

Materials for the Annual Review will be developed and circulated in advance to the Commission and intervenors. These will include, for example:

- Forecasts of customer growth and inflation to be used in the determination of the formula-based O&M and Net Gas-Plant-in-Service (and related) calculations.
- Forecasts of revenues, cost of gas, property taxes and other flow-through items.
- Reporting on SQIs, incentive mechanisms, projected results and any other items identified in the negotiated settlement.

It is proposed that the process following the Annual Review each year will also be similar to the process in the 1998 – 2001 PBR. After the Annual Review Terasen Gas will file an application with the Commission for the following year's rates which responds to any issues raised at the Annual Review meeting. Intervenors would then be permitted to comment on the Company's application and the Company would be permitted reply comment. The Commission would then issue its order after consideration of these filed materials.

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1. Reference: Proposed PBR Plan Elements Page C-8, Para 4

"Stakeholders have indicated that certain expenses are actually partially controllable and deserve some heightened attention of the company… The Company has not included such incentives in this filing but supports exploration of such ideas in the negotiated settlement process"

1.1 *Why did the Company not include expenses that are partially controllable in this PBR proposal*?

Response

Terasen Gas believes that incentives could be structured around some of the partially controllable items and that the negotiated settlement process is the most effective process for establishing which items should be incented and what benchmarks should be used to determine performance targets and incentive payout for each of the respective items.

1.2 *Please identify expenses that are "partially controllable" and that could be considered for inclusion under the PBR formula or other incentive mechanisms*.

Response

Please see the response to the question relating to page C-8 in Information Request No. 1 of Elk Valley Coal Corporation. Terasen Gas is not proposing that the partially controllable expenses be included under the PBR formula.

2. Reference: Base Delivery Rates and Adjustments Page C-10, Para 2

"The results based target is a derived factor based on CPI (BC) in order to meet the PBR design principles: it is administratively simple, it is easy to understand and it facilitates communication with customers in a manner that has meaning to customers. A target based on CPI (BC) achieves these principles most effectively. CPI (BC) is a tested and understood measure and it as used in the 1998 PBR."

2.1 *In addition to deriving a factor that is administratively simple and easy to understand, please comment on the appropriateness of the sue of the CPI (BC) in relation to Terasen Gas Inc's controllable costs that includes not only O&M expenditures but, in the case of the proposed 2004-2008 PBR plan, also Net-Gas-Plant-in-Service expenditures (i.e. how does the CPI (BC) relate to the change in Terasen Gas Inc's controllable costs?)*

Response

Terasen Gas believes that CPI (BC) is an appropriate measure to use in the proposed PBR mechanism.

With regard to O&M expenditures, employment expenses (wages, salaries and benefits) are a major component of the expenditures. The settlements with the unionized employees of Terasen Gas include requirements for wages to increase annually at 3%, a rate greater than forecast inflation. Recent experience with employment-related benefits has been that those expenses are increasing at a rate greater than inflation. Other components of O&M include supplies and outside services, and it is reasonable to assume that costs of that type will also increase in line with inflation.

With regard to net gas-plant-in-service, there are inflationary pressures that have a major influence on costs. While net gas-plant-in-service includes historic assets, all capital additions, reinforcements and replacements of capital assets are undertaken at current costs. For example, a main that may have been installed in the 1950's in what was then a rural area at a cost of $50,000 would now have minimal depreciated value (and therefore be in rate base at a minimal amount). When that main requires replacement the area may now be heavily populated and the replacement cost could be many times the original cost of $50,000 and many, many times the depreciated value recorded in rate base. The result will be that the costs of the replacement main will far out distance inflation, while Terasen Gas is only seeking a CPI adjustment. The capital costs associated with new customers include a mix of labour costs and material costs including the costs of new mains, meters and service lines; the labour costs can be expected to increase at greater than the forecast inflation while material costs can be expected to increase in line with inflation.

Terasen Gas also experiences cost increases that relate to capital expenditures for new plant, and to replacements and reinforcements of existing plant, such as safety and integrity programs that were not included in historic costs. An adjustment of historic costs by CPI does not take into account the effect of higher costs relating to requirements of this type.

The appropriateness of the CPI (BC) adjustment can also be seen in the forecasts that the Company has provided. The costs respecting O&M and net gas-plant-in-service that are used in the determination of the PBR-related rate forecasts are lower than those types of costs under the forecasts of comparable costs under traditional rate setting procedures.

Please also see the response to BCUC Staff Question 10.2.

2.2 *Please provide for each of the years 1993-2002 a comparison of increases in Terasen Gas Inc's controllable costs and the rate of in??*.

Response

The following three tables show Terasen Gas Inc.'s actual net gas-plant-in-service, net O&M, and gross O&M per customer annual rate of increases compared to inflation (BC CPI) for the requested period. The calculations in the net O&M table include the effects of the applied overhead capitalized percentage rate reductions during this period. For comparison the table for gross O&M shows the annual rate of increases without the effects of the overhead capitalized rate changes.

ACTUAL MID-YEAR NET GAS-PLANT-IN-SERVICE (NGPiS)

			Mid-Year NGPiS			
Line No.	Year	Average Customers	Amount ($000)	Per Customer	Per Customer % Increase	BC CPI
	(1)	(2)	(3)	(4)	(5)	(6)
1	1993	642,442	$1,093,573	$1,702		
2	1994	665,805	$1,200,674	$1,803	5.9%	1.9%
3	1995	685,400	$1,310,033	$1,911	6.0%	2.3%
4	1996	703,231	$1,409,701	$2,005	4.9%	0.9%
5	1997	720,464	$1,474,044	$2,046	2.0%	0.7%
6	1998	734,152	$1,522,875	$2,074	1.4%	0.3%
7	1999	745,234	$1,579,325	$2,119	2.2%	1.1%
8	2000	755,079	$1,603,454	$2,124	0.2%	1.9%
9	2001	760,236	$2,029,534	$2,670	25.7%	1.7%
10	2002	766,929	$2,089,264	$2,724	2.0%	2.3%

ACTUAL NET O&M

Line No.	Year	Average Customers	Net O&M Amount ($000)	Net O&M Per Customer	Net O&M Per Customer % Increase / (Decrease)	BC CPI
	(1)	(2)	(3)	(4)	(5)	(6)
1	1993	642,442	$93,181	$145		
2	1994	665,805	$96,221	$145	0.0%	1.9%
3	1995	685,400	$104,560	$153	5.5%	2.3%
4	1996	703,231	$109,550	$156	2.0%	0.9%
5	1997	720,464	$117,965	$164	5.1%	0.7%
6	1998	734,152	$124,821	$170	3.7%	0.3%
7	1999	745,234	$113,068	$152	-10.6%	1.1%
8	2000	755,079	$123,296	$163	7.2%	1.9%
9	2001	760,236	$132,408	$174	6.7%	1.7%
10	2002	766,929	$142,110	$185	6.3%	2.3%

ACTUAL GROSS O&M *

Line No.	Year	Average Customers	Gross O&M * Amount ($000)	Gross O&M * Per Customer	Gross O&M * Per Customer % Increase / (Decrease)	BC CPI
	(1)	(2)	(3)	(4)	(5)	(6)
1	1993	642,442	$126,812	$197		
2	1994	665,805	$130,618	$196	-0.5%	1.9%
3	1995	685,400	$141,742	$207	5.6%	2.3%
4	1996	703,231	$146,328	$208	0.5%	0.9%
5	1997	720,464	$150,496	$209	0.5%	0.7%
6	1998	734,152	$153,916	$210	0.5%	0.3%
7	1999	745,234	$142,334	$191	-9.0%	1.1%
8	2000	755,079	$146,603	$194	1.6%	1.9%
9	2001	760,236	$156,202	$205	5.7%	1.7%
10	2002	766,929	$167,310	$218	6.3%	2.3%
11						
12						

13 * Gross O&M excludes vehicle lease and Fort Nelson.

3. Reference: Page C-11, Para

"Changes in the "Other Revenue" category labelled "Late Payment Charges" will also be subject to adjustments by the results based target.

3.1 *In placing Late Payment Charges under the PBR adjustment, does this result in a lower level of Late payment Charge than it would if it were not subject to the adjustment*?

Response

With the Late Payment Charge ("LPC") revenues being subject to the PBR adjustment formula, the actual amount of LPC revenues collected may be either higher or lower in any particular year than the formula based amount that was used in setting rates. LPC revenues are tied to the prevailing level of customers' rates, which are more linked to fluctuations in commodity prices than to the delivery charges. The Company's rationale for proposing LPC revenues be subject to the PBR adjustment mechanism is that LPC revenue are influenced by similar factors as bad debt expense which is in the formula-based O&M calculation. LPC revenues tend to increase at the same time that bad debt expense increases and therefore the change in the revenue item acts as a partial hedge against the change in the expense item, and vice versa.

3.2 *How frequently has this charge been adjusted in the last 10 years*?

Response

The LPC has not been adjusted in the last 10 years. It has been at 1.5% for accounts that are overdue and 1.5% per month thereafter during this entire period. With the repatriation of customers from the BC Hydro billing system, Terasen Gas now receives the LPC revenues for Lower Mainland customers. Prior to July 1, 2002, B.C. Hydro retained the LPC revenues received from Lower Mainland customers. Since Terasen Gas previously only received LPC revenues from its Interior customers, revenue requirement applications included only a forecast of Interior LPC revenues in the rate setting calculations.

3.3 *Please provide the annual levels of this charge for the last 10 years*.

Response

Particulars	Late Payment Charges ($000)
1993	$ 618
1994	703
1995	725
1996	750
1997	831
1998	787
1999	1,050
2000	1,332
2001	1,798
2002	1,976

The major reasons for the increases over the years are the increase in gas commodity changes and customer growth.

3.4 *In subjecting the Late Payment Charge to the PBR adjustment in the absence of reduction in the incidence of customer late payment would those customers that pay on time be taking on a larger portion of the costs associated with late payment created by delinquent customers*?

Response

As indicated in the response to Question 3.1 above, the Company does not expect that actual LPC revenues will be biased in either direction from the formula based amount. Beyond this, the LPC revenues are greater than the associated costs so the rates of all customers in a class are lowered by the excess of revenues over costs. By including LPC revenue in the PBR formula, customers that pay on time are insulated from variances in the costs associated with the late payment created by delinquent customers

3.5 *Does the Late Payment Charge, at least in part, act as a deterrent to late payment, or incentive to timely payment of accounts*?

Response

Yes, the LPC does, in part, act as a deterrent to late payment or as an incentive to timely payment.

3.6 *If so, would subjecting the Late Payment Charge to the PBR adjustment minimize this charge's role in deterring late payment, or incenting timely payment*?

Response

No. The Company does not intend to change the level of the LPC that customers will be required to pay on overdue accounts. It will continue to be 1.5% per month. The level of deterrent seen by a customer with a delinquent account will be unchanged.

The reference in the Application to including the Late Payment Charge in the PBR adjustment formula refers only to the forecast total amount of revenues credited against revenue requirements each year in the rate-setting process.

4. Reference: Page C-15, Para 3

"Instead, the Company is proposing that the application of the sharing mechanism be adjusted to allow the recovery of all restructuring costs out of the actual savings realized prior to the commencement of any sharing between the Company and customers".

4.1 *In its sharing mechanism proposal is Terasen Gas Inc proposing that the revenue requirement of effecting efficiencies are incremental to it's base revenue requirement, or is it proposing to reduce its base revenue requirement by the cost of efficiency measures*?

Response

The Company is proposing that its revenue requirements would not be increased by the amount of the restructuring costs. The restructuring costs do not affect the base revenue requirement. The proposal set out in the Application is that restructuring costs would only be recovered by Terasen Gas if there were earnings above the allowed ROE. Any cost savings above the restructuring costs would be shared 50:50 between the Company and customers through the earnings sharing mechanism once restructuring costs were fully recovered. Please also see the responses to BCUC Staff Questions 1.11.1 through 1.11.5.

4.2 *If it is the former, please explain why the cost of efficiency measures is treated as an incremental revenue requirement given that such measures would be expected as a regular part of conducting business under continuous improvement strategies*.

Response

The Company is not requesting additional revenue requirements to recover restructuring costs; they will only be recovered if the actual earnings of the Company in a year are greater than the ROE allowed by the Commission ROE adjustment mechanism for that year.

5. Reference: Page C-17, Para 2

"Terasen Gas Inc believes that maintaining a high level of service quality and customer value is important to the success of the Company under any regulatory scheme."

5.1 *When was the last time that Terasen Gas Inc conducted a customer survey to determine what customer's value and expect in terms of gas utility service*?

Response

Terasen Gas has conducted customer satisfaction survey research on a continual basis since 1993. Studies are conducted across all major customer segments. The surveys track a broad range of attributes that strive to integrate the many elements of customer interactions with Terasen Gas, from field services to billing.

5.2 *What were the results of the survey*?

Response

Analysis of the response patterns provided by Terasen Gas residential customers allowed for the calculation of importance of factors relating to overall satisfaction with the Company's service. In addition to safety and reliability, three areas of importance were identified by Terasen Gas customers, and they were: billing, corporate image, and marketing and communications.

6. Reference: Page C-24, Para 6

6.1 *What productivity improvement analysis did Terasen Gas Inc. conduct in arriving at a proposed adjustment factor of 0.75%*?

Response

Terasen Gas did not perform a productivity improvement analysis in arriving at the proposed adjustment factor of 0.75%. Please see the response to BCUC Staff Question 1.1.

6.2 *What productivity factors have been established for other Canadian natural gas utilities with multi-year PBR regulatory regimes which include capital expenditures*?

Response

Terasen Gas has not done a survey of the productivity factors used by other Canadian utilities. A productivity factor is only one of many factors that may be in a PBR plan. Any comparison of capital productivity factors across jurisdictions would not be meaningful outside the context of each utility's specific operating circumstances and the overall PBR plan in which it is included.

7. Reference: Page C-A-1, Page 5, Para 2

"Industry standards are commonly used as benchmarks in the electricity industry. …However, in the Gas industry, less consistency exits between gas utilities and industry associations."

7.1 *Are there similarities in the customer service indicators (e.g. time to answer phone) monitored by the electricity and gas utilities*?

Response

Yes, some of the 2004 – 2008 Service Quality Indicators proposed by Terasen Gas are similar to customer service indicators within electricity utilities (see response to Question 7.2 below). During the process of developing the list of proposed 2004 – 2008 Service Quality Indicators both electric and gas utilities were reviewed to determine what other utilities are tracking as Service Quality Indicators and to assist in determining a proposed Service Quality Indicator benchmark.

7.2 *If so which indicators monitored by Terasen Gas Inc. might be those also monitored by the electricity utilities*?

Response

Terasen Gas is proposing to track the speed of answer to emergency calls, and speed of answer to non-emergency calls as part of the 2004 – 2008 Service Quality Indicators. These two Service Quality Indicators are being tracked by some electric utilities as customer service indicators.

7.3 *Has Terasen Gas Inc. compared its performance standards with those of the electricity utilities*?

<u>Response</u>

Terasen Gas has compared its performance standards with those of the electricity utilities only on an ad hoc basis where common measures were found. For example, speed of answer (percent of calls within 30 seconds by a person) is a common measure. However, the significant difference between gas and electric distribution systems makes operational comparisons difficult. Electric systems typically fail “safe” whereas gas systems typically fail “unsafe”. This fundamental difference results in quite different operating requirements. For example, emergency response times are not as critical for an electric utility because fuses or breakers usually shut off power when a line is broken. When a gas line is broken, gas will continue to escape until someone arrives on site to stop it.

7.4 *If so, please provide the results of the comparisons*.

<u>Response</u>

No formal comparison has been made between the performance standards for Terasen Gas and those of the electricity utilities.

7.5 *Are there other customer service indications utilized by other Canadian natural gas utilities which Terasen Gas Inc. has considered and rejected? If so, why were the rejected*?

<u>Response</u>

Terasen Gas did consider a customer satisfaction Service Quality Indicator but rejected it because the Company believes that customer satisfaction surveys are not suitable as a Service Quality Indicator as they are a qualitative measure not an objective quantifiable measure.

It has been the Company’s experience with customer satisfaction surveys that they can be highly impacted by exogenous factors such as an increase in the commodity price of natural gas.

Please see the response to Question 7.6 below

7.6 *Are there other SQI's utilized by other Canadian natural gas utilities which Terasen Gas Inc. has considered and rejected? If so, why were they rejected*?

Response

Yes, there are a number of examples of Service Quality Indicators that Terasen Gas considered but rejected. Some examples are:

- System Reliability
- Preventative Maintenance Activity
- % of appointments kept
- New Services Installation
- Meter Exchange Lock-offs
- % of site visits un-resolved
- Customer Satisfaction

All the above proposed Service Quality Indicators were evaluated against the list of eight criteria in appendix C-A-1, p 3 of the Application.

The main reasons for rejecting these Service Quality Indicators were that Terasen Gas does not have the technology / system to track the Service Quality Indicator and that Terasen Gas was concerned there would be issues around setting the Service Quality Indicator Benchmark. For example Terasen Gas rejected the Preventative Maintenance Activity Service Quality Indicator that is tracked by Gaz Metropolitain because of the concern around setting one Benchmark over the term of the PBR. The preventative maintenance activity as scheduled within Terasen Gas is not the same each year raising the issue that Terasen Gas could manipulate the benchmark to their needs.

7.7 *The Performance Measure Billing Activity measures the "percentage of bills accurate based upon input data". How will this measure account for meter reading estimates*?

Response

This measure does not account for meter reading estimates as long as the input data used in the determination of the estimate is correct and the calculation applied agrees to the functional specifications determined by Terasen Gas in 1999. If the data used to determine the estimate is corrupted due to changes made by CustomerWorks or if the defined calculation formula is incorrect, the subsequent consumptions would result in billing errors and would be captured in this measure.

7.8 *Has Terasen Gas Inc. considered measuring the number of customer complaints overall and the number of customer complaints resolved? If so, why was an SQI related to customer complaints rejected*?

Response

Yes, Terasen Gas did look at tracking customer complaints as a possible Service Quality Indicator but does not believe that the number of complaints provides a good indication of performance. Aside from the difficulty in defining a complaint (as opposed to an inquiry), the correlation between the actions of the Company, and the number of complaints, is not well established. Minor difficulties affecting many customers may lead to an inordinate number of complaints, while a more serious circumstance that is regional or local in nature may result in very few complaints. Also customer complaints may be influenced by exogenous factors, most prominently the commodity price of natural gas. As a result, customer complaints are not a proposed Service Quality Indicator.

7.9 *Terasen Gas Inc. states that the SQI Leaks per kilometer of Distribution Mains Due to System Deterioration was intended to indicate the integrity of the distribution system (Appendix C-A-1, page 4). Other gas utility companies (Enbridge, Union) have survey programs that allow the utilities to monitor and assess the system integrity. Has Terasen Gas Inc. considered the use of surveys as a measure that would indicate the integrity of the distribution system? If not, why not*?

Response

Yes, Terasen Gas tracks the integrity of its distribution system through leak survey and scheduled preventative maintenance programs. The proposed "directional indicator" Distribution System Integrity is proposing to track leaks per kilometer of distribution mains. This directional indicator will track all leaks found on distribution mains including leaks found during scheduled leak survey programs.

Please also see the response to LMLGUA et al Question 19.1

7.10 *Terasen Gas Inc. has a five-year infrastructure plan for category B expenditures, including expenditures related to pipeline integrity. Can the infrastructure plan be linked to an SQI to measure system integrity? If not, why not*?

Response

Not directly. Category B expenditures are often for system reliability and system reinforcement to ensure that gas supply is never interrupted. The electric industry sometimes measures system reliability in terms of numbers of "outages" per year, or numbers of customers interrupted. This is not a good measure for the gas distribution system because any outage on a gas system is dangerous and must be avoided.

Therefore Category B expenditures cannot be easily linked to a Service Quality Indicator.

Category C expenditures are for replacing leaking or aged system, at least in part. The objective of the PM system is to develop an objective preventative maintenance tool that will allow system integrity to be measured and managed in a measured way. For example, Mean Time Between Failure (MTBF) is used in some industries to determine the appropriate levels of expenditure on maintenance for various types of equipment. Ultimately the PM system will allow these types of measures to be developed, but it will be several years before enough data and experience can be gathered to reliably predict cause and effect. No one else in the gas industry is even attempting to do this.

Please also see the response to LMLGUA et al Question 19.1

7.11 *What is Terasen Gas Inc.'s policy with respect to gas utilization infractions? Does the company have a safety program in place? If so, please provide details of the program. What guidelines are in place to ensure that the program is carried out? Is Terasen Gas Inc. amenable to having an SQI that measures gas utilization infractions? If not, why not*?

Response

It is not clear what is meant by the term "gas utilization infraction". Terasen Gas has significantly reduced its role downstream of the meter. Nearly all of this work is performed by the appropriate trade sector. Terasen Gas does respond to leaks and odour calls, or any undefined call that sounds like a safety issue. Terasen Gas will make the situation safe by shutting the gas off or shutting off and "red tagging" a gas appliance, but that is as far as the utility will go. All repair or further investigation is the responsibility of the customer. Terasen Gas does periodically send out safety notices to customers reminding them to have their appliances checked by a qualified gas fitter.

Reference: Application Section C. Multi-Year PBR Mechanism, Subsection 4 Enhancing the PBR Model, and Subsection 5d Sharing Mechanism.

Preamble: Terasen is proposing to recover the cost of upfront investments in "process changes and organizational restructuring" before any savings are shared with consumers.

Request:

(a) *Please describe in detail Terasen's proposed mechanism for tracking the costs and savings for each investment in "process changes and organizational restructuring".*

Response

Please see the responses to BCUC Staff Questions 1.9.1, 1.11.1, 1.11.2, and 1.11.3.

(b) *Will Terasen prepare a Business Case for each investment in process changes and organizational restructuring?*

Response

No, please see the response to 1(a) above and to LMLGUA et al Questions 4.1 and 4.2.

(c) *Please describe in detail all process changes and organizational restructuring planned or being planned by Terasen for the period 2004 – 2008.*

Response

Please see the response to LMLGUA et al Question 18.2.

Reference: Application Section C. Multi-Year PBR Mechanism, Subsection 5f Exogenous Factors, and Subsection 8 Rate Forecasts.

Preamble: Terasen has provided forecast rate increases under Cost of Service, Decision, and PBR Formula scenarios.

Request:

(a) *Please confirm that no costs related to unbundling implementation are included in any of the scenarios*.

Response

That is correct. None of the scenarios presented in the Application include any provision for unbundling costs. Under the Company's proposal the Company will not be at risk for costs of unbundling. This is discussed in the Application at page C-16.

(b) *If unable to confirm 2(a) above, please provide details of any unbundling costs included in any of the scenarios*.

Response

Not applicable. Please see the response to Question 2(a) above.

Reference: Application Section C Multi-Year PBR Mechanism, Subsection 5h Annual Review and Subsection 5i Mid-Term Assessment Review.

Preamble: A PBR mechanism embodies much more of a partnership arrangement between stakeholders and the utility than does a traditional regulatory process. The success of a PBR mechanism depends in large part on the existence of a high level of trust among all parties, and on the full exchange of timely information. In the absence of formal regulatory proceedings, stakeholders require a forum to receive information, provide input, and to evaluate the analyses provided by the utility on programs and expenditures that will impact their rates, services, and service levels. In other jurisdictions, formal processes have been established to provide such a forum, and include representatives of stakeholders, the utility, and (in some instances) the regulator.

Request:

(a) *Will Terasen commit to the establishment of a formal process during the PBR period to allow stakeholders to receive information and provide input into major decisions and expenditures that will impact rates, services, and service levels*?

Response

The Company is committing to formal processes to allow stakeholders to receive information during the PBR Plan period. Terasen Gas proposes that the Annual Review process be in place during the PBR Plan period and that a more comprehensive Mid-term Assessment also be undertaken. This is described in the Company's response to LMLGUA et al Question 31. These forums will allow stakeholders to ask questions about operations and future plans and provide feedback to the Company.

Because customer rates will be set by formulas for O&M and Net Gas-Plant-in-Service cost items, decisions that Terasen Gas takes concerning those activities will not affect rates. Service levels will be preserved and performance on SQIs reported during the Annual Reviews.

Major capital expenditures will continue to be authorized pursuant to CPCN applications during the term of the PBR Plan, however the Company proposes that customers' rates would not be affected by these expenditures during the term of the PBR Plan.

Other than through the CPCN approval process, the Company is not proposing to solicit pre-approval on operating and capital decisions during the PBR Term as this would be inefficient and cumbersome from an operational perspective. The review processes and regulatory oversight proposed for the term of the PBR Plan are, in the Company's opinion, sufficient to safeguard the stakeholders' interests.

(b) *If unable to make the commitment requested in 3(a) above, please provide Terasen's rationale for not supporting such a process*.

Response

Please see the response to 3(a) above.

TERASEN GAS INC.

MULTI-YEAR PERFORMANCE BASED RATE PLAN FOR 2004 – 2008

RESPONSE TO ELK VALLEY COAL CORPORATION
INFORMATION REQUEST NO. 1

The Elk Valley Coal Corp. ("Elk Valley") is an Intervenor in the above mentioned proceeding and has the following initial Information Request.

Tab C -C-8

"The PBR plan adjusts rates each year to flow through changes in expenses over which the company has limited influence."

1. *Please provide a list of the above expenses, a brief explanation, and assuming the existing corporate risk profile, what incentives can be provided to the company to mitigate these cost pressures*.

   Response

   Please see the response to BCUC Question No. 1.5.

C-8

"However, certain components of rate base such as working capital and deferred charges remain less controllable."

1. *Please provide suggestions as to incentives which could be provided to the company to enhance the control of these and similar costs.*

   Response

   In discussions with stakeholders and during the May 15 workshop, a number of parties indicated support for creating positive incentives around items that have historically be treated as flow through items. This would encourage the Company to take further measures to mitigate less controllable items such as property taxes.

   The Company does not have any fully developed ideas for such incentives but would like to explore these with stakeholders either during the NSP or between the NSP and the Annual Review in November of this year.

   Positive incentives for property tax for instance could be developed based on the Company's successful efforts to challenge specific assessments and retaining a portion of the benefit realized as a consequence, or at an overall level by keeping a portion of the savings achieved (i.e. the variance from the forecast included at the Annual Review each year) on the projected property tax expense.

The difficulty of the second alternative is in measuring whether the benefits were achieved through Company efforts or resulted from factors beyond the Company's control.

Pension expenses were also raised as an item that could be subject to an incentive. The Company would like to explore opportunities to create positive incentives around such costs, however, so many factors come into play in the determination of pension costs that are beyond the Company's control that the Company does not have a suggestion around this item.

Please also see the response to BCUC IR No. 1 Question 1.5.

C-15

" Sharing mechanisms are generally put in place to allow participation by customers in gains and losses of the utility under the P B R Plan."

1. *Please suggest incentives which would further incent the company to achieve net savings as soon as possible thereby enhancing the net present value to the customers*.

Response

It is difficult to envision further incentives that could accelerate savings and enhance returns to customers without it being at the expense of the Company. For example, an asymmetric sharing in the early years favouring the Company (say 75:25) might encourage more risk taking due to higher recoveries but this would defer benefit realization of the customer.

Conversely, enhanced sharing in favour of the customers in the early years would increase the benefit percentage directed to the customers but would extend the recovery period, and not incent the Company to take on longer term payback initiatives. In such a case the customers would get a greater share of the benefit pie, but it could be a smaller pie, which does not meet the objective set out in the question.

Terasen Gas believes that equal sharing and the recovery of restructuring costs out of benefits realized before sharing commences, provides a good balance that encourages the Company to maximize benefits for all parties.

An alternative is to have 50:50 sharing commence immediately which would result in up front costs being shared by customers along with immediate benefit sharing. Customers receive the same overall benefits but sharing starts sooner.

Tab D -D-1

"Approximately two-thirds of the Company revenue requirements (excluding cost of gas want) relate to costs associated with past capital investments."

1. *Please suggest, incentives that could be put in place to mitigate the impact of past capital costs investments*.

Response

Past capital expenditures have been approved by the Commission and cannot now be changed. In light of this the Company has no suggestions for incentives to mitigate the impact of past capital expenditures but is willing to explore suggestions or proposals by stakeholders that would provide such incentives either during the NSP or thereafter.

Tab E-E-16

“Current assessment indicates that gas meter “lock offs” in the Lower Mainland will increase 1000 % from approximately 1800 prior to repatriation to over 19,000 per year in 2003 and beyond."

1. *Please indicate what steps can be taken to " reduce and mitigate the cost of the above “lock offs”*.

Response

Repatriation of the Lower Mainland billing system from B.C. Hydro is the main reason for the increased activity levels. When B.C. Hydro managed both gas and electricity B.C. Hydro would shut off the electricity to force payment of bad debts. The gas meter wasn’t shut off in most cases. Customers have a more immediate need for electricity and were more prompt in paying outstanding bills. Now that the gas bill is separate the gas meter has to be shut off. Increased commodity costs make the matter worse. The activity levels are expected to fluctuate with economic conditions and commodity price, but hopefully will begin to come down as customers become familiar with separate gas bills and become “educated” by a determined collection process.

The cost of the lock-offs in the Lower Mainland for residential and commercial accounts is borne by CustomerWorks and is included in the fixed price per customer contract. The lockoff activity, formerly completed by B.C. Hydro employees, is currently being completed by another smaller non union contractor working for CustomerWorks at its cost.

The impact to Terasen Gas is primarily in the reconnect and relight activity which increases in parallel with the lock-offs. Most of the cost of the reconnect activity is recovered from locked off customers however there is a need to have a larger number of trained and available resources to perform the additional reconnects.

Although the increased lock-off relight activity has had a negative impact on Terasen Gas' costs, the alternative to continue to deliver gas to customers who do not pay is substantially more costly.

E-40

"The largest component is comprised of service, materials and supplies, totalling $ 9.9 million or 17% of O& M. Of this amount, Bad Debt represents $5.1 million.

1. *Please explain what initiatives/incentives can be taken to reduce significantly Bad Debt expense.*

Response

Since the repatriation of the Lower Mainland customers and the integration of all residential and commercial customers onto a single billing platform a number of changes have been implemented or are planned to address bad debt expense. These include:

1. Monthly billing: All customers are now billed monthly. This provides a more timely collections processing cycle than was available with bi-monthly billing.
2. Use of a Predictive Dialling technology: This supports automated outbound overdue reminders for customers early in the collections cycle.
3. New customer credit assessment: New residential customers are now asked for a security deposit at the time of their initial application. In lieu of a deposit a new customer can authorize an external credit check with a credit scoring agency. If approved the deposit is waived. The previous Interior policy requiring security deposits for all new commercial customers has been extended to the Lower Mainland customer group.
4. Temperature restricted lock off parameters: Terasen Gas is currently reviewing its policy related to weather restricted lockoffs to ensure the optimal temperature parameter is utilized in determining the schedule for lockoff activities.
5. Payment Options: An initiative is being planned for this fall to encourage customer participation in pre-authorized payment. This payment option is beneficial in ensuring prompt payment. Terasen Gas is also continuing to investigate optional "user-pay" credit card options for high risk customers.
6. Owner Agreements: Terasen Gas is currently reviewing a program to work with landlords to ensure customer moves are processed in a timely manner and to minimize lost gas during periods of vacancy.

Tab -F -F-3

"Natural gas commodity prices will continue to be subject to some price volatility "

1. *Please provide an estimate of the price volatility throughout the "full term" period of the PBR inclusive of the estimated price for each year from 2004 to 2013.*

Response

The referenced statement was not intended to imply a detailed analysis of the pricing dynamics for natural gas, and was intended only to recognize that the physical and economic realities underlying regional gas supply and delivery are likely to result in some price volatility during the forecast period. The traditional supply areas to this region continue to increase access to other continental markets. At the same time, regional peak day demand scenarios show increasing reliance on demand curtailments to balance with available supply and transmission. Implicit in this type of supply and demand picture is an expectation of short-term price volatility to bring demand into alignment with available supply and transmission.

The level and timing of this price volatility is inherently unpredictable within any given year, let alone across the "full term" of the PBR. Regional and continental weather patterns, regional and continental economic developments, regional and continental supply developments, and regional transmission and storage developments will all have an impact on the timing and degree of volatility in natural gas prices during the period under consideration.

General

1. *Please explain, in a summary format, what procedures and mechanisms are in place or could be put in place to "cut costs" on an ongoing basis. e.g. Monthly quarterly, annually*

Response

The incentives under a PBR Plan and employee incentive arrangements encourage continuous improvement in operations.

Cost efficiency is entrenched in all facets of the Company's management and control processes starting with the annual planning cycle:

- High level cost targets are established each summer followed by detailed budgeting in the fall
- Monthly departmental and executive level operations reviews/reporting are undertaken
- Ongoing operating adjustments are made to address unforeseen incidents or impacts on the business
- Employees at all levels are encouraged to bring forward ideas to optimize operating performance.

In addition to the above the Company utilizes a number of approaches to manage costs on an ongoing basis:

- Personal performance plans
- Performance benchmarking
- Outsourcing
- Competitive tendering
- Automated systems for work management, dispatch and time capture, etc.

TERASEN GAS INC.

MULTI-YEAR PERFORMANCE BASED RATE PLAN FOR 2004 – 2008

RESPONSE TO ELK VALLEY COAL CORPORATION INFORMATION REQUEST NO. 2

General

1. *Please explain generally what the British Columbia Consumer Price Increase ("CPI) is attempting to measure*

Response

According to Statistics Canada:

> "The reference population for the Consumer Price Index (CPI) has been represented, since the 1992 updating of the basket of goods and services, by families and unattached individuals living in private urban or rural households. The official CPI is a measure of the average percentage change over time in the cost of a fixed basket of goods and services purchased by Canadian consumers."

Please also see the response to BCUC IR No. 1, Question 1.1.

2. *Please explain generally what the Bank of Canada's core inflation measure is attempting to measure ,inclusive of the list of items excluded there from and generally the reasons for the exclusion*.

Response

The Bank of Canada web-site defines core CPI as:

> "A variant of the CPI that excludes the eight components with the most volatile prices—which account for 16 per cent of the CPI basket—(fruit, vegetables, gasoline, fuel oil, natural gas, mortgage interest, intercity transportation, and tobacco products) as well as the effect of changes in indirect taxes on the remaining components. (Prior to May 2001, the Bank of Canada used the CPI excluding food, energy, and the effect of changes in indirect taxes as its measure of core CPI.)"

The Bank indicates that it uses core CPI to guide short-term policy decision making. Core CPI excludes the most volatile items that could influence CPI in the short term. While this may be important for short-term monetary policy decisions, Terasen Gas believes that using forecast annual CPI is reasonable for the purposes of PBR.

3. *Please provide the British Columbia CPI from 1995 to date*.

Response

The actual B.C. CPI from 1995 to 2002 is presented in the table below.

The data is from B.C. Provincial Government data sources:
(www.bcstats.gov.bc.ca/data/dd/prices.htm).

Particulars	B.C. CPI Actual
1995	2.3
1996	0.9
1997	0.7
1998	0.3
1999	1.1
2000	1.9
2001	1.7
2002	2.3

4. *Please provide the Bank of Canada's core inflation measure ,on a similar basis to the above ,from 1995 to date*.

Response

The actual Bank of Canada's core inflation measure from 1995 to 2002 is also presented in the table below. The source is (www.bankofcanada.ca/en/cpi.htm).

Particulars	B.C. CPI Actual	Bank of Canada Core CPI [(1)]
1995	2.3	1.8
1996	0.9	2.1
1997	0.7	1.3
1998	0.3	1.3
1999	1.1	1.4
2000	1.9	1.8
2001	1.7	1.6
2002	2.3	2.7

1. Core CPI: The CPI excluding the eight most volatile components (fruit, vegetables, gasoline, fuel oil, natural gas, mortgage interest, inter-city transportation and tobacco products) as well as the effect of changes in indirect taxes on the remaining components. CANSIM identifier for this series (in level terms) is B3328.

TERASEN GAS INC.

MULTI-YEAR PERFORMANCE BASED RATE PLAN FOR 2004 – 2008

RESPONSE TO LOWER MAINLAND LARGE GAS USERS ASSOCIATION et al.
INFORMATION REQUEST NO. 1

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1. Tab A, Paragraph 9

Terasen Gas Inc. ("Terasen") proposes deferral accounts with regard to the revenue stabilization adjustment mechanism and the gas cost reconciliation account. In the workshop on May 15, 2003, Terasen indicated that they agreed that the Company should not derive any benefit from tax reductions and those benefits should accrue to customers. It is the Intervenors' understanding that Terasen has in the past two months had discussion with Commission staff about accruing a benefit to shareholders as a result of tax reductions in recent years.

1.1 *Please provide all correspondence with the Commission including responses to information requests which deal with the tax treatment of these deferral accounts.*

Response

The attached correspondence (Appendix A) includes the March 18, 2003 letter of BC Gas Inc. requesting the proposed treatment, the Staff's Information Request, and the Commission's Order and Reasons for Decision. The response to the Staff's information request was filed confidentially with the Commission due to it containing earnings and tax details of unregulated affiliates of the Terasen Gas. This response is therefore not attached.

The application to the Commission contained in the March 18 letter related to circumstances that arose because of the unanticipated large increases in gas commodity costs in 2000 and 2001. Due to the dramatic increase in the GCRA balance that accompanied the gas commodity increase and the subsequent reduction in corporate income tax rates the BC Gas group of companies lost benefits that had been expected from tax planning the had been undertaken before the increase in gas commodity costs. The March 18 letter sought recognition of the decrease in the value of those benefits in the Commission's treatment of the GCRA deferral account.

1.2 *Is there any reason why deferral account tax treatment should be any different than treatment of taxes in matter of within the PBR mechanism*?

Response

No. The Company is not proposing any different treatment.

1.3 *It is the Intervenors' understanding that Terasen has requested that $4 million of the benefit of tax reduction should accrue to Terasen shareholders. Please confirm that in order to achieve a $4 million benefit to shareholders that would require an $8 million before tax revenue requirement to be collected from customers*.

Response

Please see the response to Question 1.1 above. The application to the Commission sought recognition of the fact that the BC Gas group of companies had suffered a loss in the value of tax planning benefits due to the dramatic increase in gas commodity costs and the accompanying dramatic increase in the GCRA balance; it was not seeking to accrue a benefit simply because of tax rate reductions. The letter of March 18, 2003 to the Commission sets out the effect of the request.

1.4 *What is Terasen's position with regard to the level of financial obligation to customers which should be in question before the matter is brought to the attention of stakeholders as opposed to holding a Commission staff to company discussion*?

Response

Terasen Gas does not believe that the level of financial obligation determines whether a question is brought to the attention of stakeholders as opposed to holding a Company to staff discussion. For example, gas supply matters may involve significant amounts of money but may not warrant stakeholder review whereas matters such as Code of Conduct or Transfer Pricing which may involve relatively small amounts of money may be of interest to stakeholders. The proposed PBR Plan includes Annual Reviews which will provide a forum for discussion of key issues facing the Company.

The appropriate forum and process for resolving issues as they arise will depend on many factors including matters of confidentiality or commercial sensitivity, relevance to the broad group of stakeholders, and administrative and regulatory efficiency. Ultimately, the BCUC has the jurisdiction to determine the appropriate forum and process for addressing any issues identified by the Company, customers or stakeholder groups.

1.5 *During the proposed PBR period, how does Terasen see stakeholders being informed as to material financial issues that the Company seeks approval for from the Commission*?

Response

As discussed above, the Annual Review process provides a forum for the discussion of all financial and operations related issues faced by the Company. Furthermore, there will be a continuing role for the Commission and its Staff in the oversight and regulation of Terasen Gas under the PBR Plan.

1.6 *What financial threshold would Terasen see as material*?

Response

As discussed in response to Question 1.4 above, Terasen Gas does not believe it is practical to define a level of financial materiality as this will vary depending on the specific circumstance. Terasen Gas will continue to file Annual Reports and will provide projected annual financial results to all stakeholders prior to the Annual Reviews. Issues of interest to stakeholders can be addressed at the Annual Reviews or through the Mid-Term Review process independent of their financial value.

2. Tab A, Page A-3, No. 10

2.1 *Please confirm that the application provides that CPCNs are exhaustively described in the application and that any further CPCNs sought by the Company during the PBR term would not be to the account of customers*.

Response

The application outlines all CPCNs that the Company is aware of at this time. It is confirmed that under the proposed PBR Plan the Company would be at risk during the PBR period for CPCNs as they are included in the Net Gas-Plant-in-Service formula.

2.2 Please confirm that Terasen does not intend to apply to the Commission for the Inland Pacific Connector, or any part thereof, to be included in rate base within the period of the applied for PBR.

Response

That is correct.

3. Tab B, Second Paragraph

3.1 *Please itemize all changes proposed by Terasen to the PBR plan approved for Terasen for 1998 to 2001 as modified by subsequent settlements in 2002 and 2003 and the proposed PBR plan for 2004 to 2008*.

Response

Please refer to the attached table that highlights the key design elements of the 1998 - 2001 Plan, the DRSM and the proposed 2004 – 2008 PBR. The reasons for selecting each of the elements of the current PBR are set out in Tab C of the Application. For ease of reference, the reasons for inclusion in the current proposal are summarised in the last column of the table.

Appendix E - Response to LMLGUA et al. Question 3.1

	1998-2001 PBR	DRSM	2004-2008 PBR	Reasons
Term	3 years + 1 year extension	5 years	5 years	better payback economics
				inreased rate certainty
O&M	formula	covered by price cap	formula	consistent with 1998-2001
Capital	Cat. A and C formula based	all capital spending covered by price cap	all capital spending covered by formula	more comprehensive incentive
	Cat. B and CPCNs excluded	no rebasing of capital	no rebasing of capital	responds to stakeholder requests
	rebased anually			
Revenue	forecast annually	industrial revenue not re-forecast	no change from 1998-2001	consistent with 1998-2001
	RSAM for core revenues	RSAM continued		
SCP Revenues	deferral account	deferral account	deferral account	consistent with 1998-2001
Escalator	CPI (BC) - 2%, 2%, 3% and 1%	CPI (BC)	CPI (BC) - 0.75%	easiest opportunities already taken
				no large IT projects to produce efficiencies
Sharing	50:50 achieved ROE variances	±200 bps - no sharing	50:50 achieved ROE variances	balance fairness/efficiency
		50:50 earnings sharing between 200-300 bps	(after recovery of restructuring)	responds to stakeholder requests
Restructuring	$3 million up front	no up-front contribution	no up-front contribution	risk of recovery to Company
	50:50 sharing through ESM	no sharing	recovered through achieved efficiencies	
Continuing Incentive	none - 3 yr. capital incentive phase-out	suggested but not specified	included: FTEI	continuing incentive throughout term
SQIs	included	expanded	expanded	responds to stakeholder requests
Annual Reviews	included	included	included	consistent with 1998-2001
Mid-Term Assessment	none	none	included	responds to stakeholder requests
Revenue Incentive	included but not specified	included (through price cap)	suggested but not specified	help offset cost pressures
DSM	included	included	included	consistent with 1998-2001
Exogenous Factors	included	no change from 1998-2001	no change from 1998-2001	consistent with 1998-2001
Flowthroughs	included	included	included	flowthrough of non-controllables
Deferral Accounts	GCRA, RSAM, Interest, Taxes, other	same as 1998 but no interest deferral	same as 1998 plus pensions & insurance	flowthrough of non-controllables
Off-Ramps	included	included	included	consistent with 1998-2001

3.2 *Please provide Terasen's explanation for those changes where such changes are not set out in the application binder (volume 1)*.

Response

Please refer to the response to Question 3.1 above.

3.3 *Please detail the proposed changes from the PBR applications filed by Terasen in 2002 and 2003 which were subsequently withdrawn and explain the reason for the changes from those filings*.

Response

Please refer to the response to Question 3.1 above.

4. Tab B

4.1 *Please describe how Terasen intends to specifically identify the restructuring costs which are to be incurred in the PBR period and identify how customers are to determine where such restructuring costs have resulted in efficiency gains which can be directly attributable to the restructuring costs such that any restructuring costs incurred by Terasen should be paid for the customers*.

Response

Terasen Gas anticipates that a definition of what is to be included as restructuring costs would be included in the settlement document negotiated between the parties and approved by the Commission. Costs that fall under the definition would then be captured accordingly and accounted for as proposed to be recovered out of the benefits achieved.

Please see the response to BCUC Staff Question 1.11.1 for further discussion of what Terasen Gas proposes as costs to come within the definition of restructuring costs.

4.2 *Please describe the review process which Terasen sees as providing the prior approval of the restructuring costs and the subsequent approval of recovery of those costs*.

Response

Please see the response to Question 4.1 above. Restructuring costs coming within the definition agreed to in the settlement document would be reported during the Annual Review each fall. Terasen Gas is not proposing that there be a process for prior approval of restructuring costs.

4.3 *Please explain how that process is any more efficient than annual revenue requirement reviews*.

Response

The process described above deals only with a relatively small element of the overall costs of Terasen Gas; there would be no need to deal with all of the O&M costs or to deal with all of the forecast capital expenditures. The process avoids preparation of annual applications and filing, explanatory workshops, extensive related Information Request proceedings and lengthy hearings. It is substantially more streamlined, less resource intensive and time consuming for all parties.

5. Tab B, Page B-2

Terasen states that the application "demonstrates that the formula based rates that will result from the proposed PBR plan are lower than the rates that forecast to otherwise arise annual cost of service reviews". Please confirm that the forecast for annual cost of service reviews do not include any discount for disallowance of capital or operating costs of Terasen resulting from those annual cost of service reviews.

Response

The revenue requirement forecasts provided represent a reasonable forecast of the revenue requirements that would arise under annual cost of service reviews. The Decision based line represents modest growth in annual revenue requirements from the base costs established through the recent Revenue Requirement proceeding. The Decision line does not add back any items that were disallowed in the Commission's Decision nor include other costs that have come to the knowledge of the Company. Given the thorough review undertaken to establish the 2003 base rates, Terasen believes that the Decision line is a conservative forecast. The cost of service is similarly based on the 2003 Decision rates but includes several items that were not included in the base, details of which are provided in the response to Question 14 below. It is difficult to prejudge the outcome of future costs and revenue requirements. Additional items could arise that have not yet been identified which could yield higher revenue requirements than those currently anticipated.

Actual revenue requirements may be either higher or lower than those currently projected. One of the benefits of PBR is that it limits the uncertainty of future revenue requirements by restricting changes in controllable costs to those established by the PBR formula.

6. Tab B, Page B-3

Terasen indicates in describing the background to the 2003 revenue requirements and multi-year PBR application that "Intervenors and Commission staff delivered extension information requests and BC Gas responded."

6.1 *Please confirm that Terasen did not respond to questions dealing with the multi-year PBR as they took the position that they were withdrawing that application as they were not prepared to have PBR dealt with in a public hearing process*.

Response

The above statement is not correct. Terasen Gas responded to numerous information requests on multi-year PBR from Intervenors and Commission Staff mainly in the responses to the first round of information requests in last year's proceeding but also in the second round of I.R. responses. The Company dealt with many Information Requests that related to the multi-year PBR period; examples of which include: BCUC Staff IR #2, Question 29 (including multiple sub-parts); Avista G-1; and Ministry of Energy and Mines 12-17 (including multiple sub-parts).

At the time of the initial information requests in 2002, the Commission had not determined what the process was that would deal with the 2003 Revenue Requirement and Multi-year PBR. At the July 17, 2002 workshop, the Company had indicated it would withdraw its multi-year application if it was to be determined through a formal hearing process rather than a Negotiated Settlement Process. It was not until September that the Commission decided to have a public hearing. With the issuance of Order G-63-02 in which the Commission indicated that the process for multi-year PBR would not occur until 2003, the focus of the proceeding became the setting of the Company's 2003 revenue requirements and establishment of a thorough public record for 2003 to be the base year of a multi-year PBR going forward. Since the multi-year PBR was not part of the public hearing process in November 2002, the Company did not respond to further information requests respecting the multi-year aspects.

6.2 *Please describe why Terasen is concerned that a PBR process should be dealt with through a negotiated settlement process as opposed to a full public hearing*.

Response

Terasen Gas believes that the Negotiated Settlement Process is the most effective manner for allowing the Company and stakeholders to establish a PBR that best satisfies each party's mutual interests. The proposed process is also consistent with the direction set out by the Commission in its Decision and as expressed by the Government in the Provincial Energy Policy. The Negotiated Settlement Process provides for open dialogue on issues important to each party which is not possible through the quasi-judicial hearing process. It is unlikely that even with the benefit of a public hearing that a Commission Panel would be able to develop a PBR Plan that better meets the interests of all stakeholders than could be achieved through the mutual agreement of those parties through the NSP.

6.3 *If in the event that parties are unable to agree with a negotiated settlement process for the PBR application presently before the Commission, would Terasen withdraw the application if parties determine that the matter should go to public hearing as is an alternative in the event of failure of negotiations*?

Response

Terasen is committed to the Commission's Negotiated Settlement Process and has not determined what action it would take if that process is unsuccessful.

If a limited number of issues were preventing a settlement, then depending on the nature of the issues, the Company would consider whether it would be agreeable to proceeding with a hearing on those matters. The Company is of the view that a Negotiated Settlement Process is the most effective way to reach a multi-year agreement whereby parties may explore options in a non-adversarial forum and reach agreement.

7. Tab B, Page B-4

Terasen states that "the results show that the Company maintained its high standard of providing safe, reliable and efficient service to customers over the prior five years". The decision also identified some significant deficiencies which arose during the PBR period with regard to Code of Conduct reporting and transfer pricing matters. How does Terasen intend to avoid these types of short falls in the applied for PBR period?

Response

As indicated in the Application the Company has responded to the Commission's determination on these matters.

The requested amendment to the definition of the transfer pricing policy was denied and so the Company continues to comply with the existing definition.

The Commission ordered that revenue requirements be reduced by $100,000 related to the website costs. The Company is now charging an additional $100,000 incrementally to Terasen Inc. over the amounts relating to IT cost recoveries included in the facilities recovery charges under the transfer pricing policy.

The Company was directed to remove all non-utility material from the Utility website. This has been accomplished and the only link on the Utility website is back to the parent company site "www.terasen.com".

The Company was ordered to ensure that the Transfer Pricing Policy (TPP) and Code of Conduct (CoC) are effectively communicated to all employees and that it files annual compliance audits detailing how it has communicated and reinforced the need for compliance with the TPP and CoC by all employees. The compliance report was filed with the Commission in April 11, 2003. The Company believes the procedures that have been introduced to enhance compliance with the TPP and CoC as outlined in the report filed with the Commission noted above, the ongoing oversight of the Commission, and the input and interaction of stakeholders with the Company as part of the Annual Reviews and the Mid-term Assessment as proposed in the PBR Plan, should avoid recurrence of any of the issues that arose earlier.

8. Tab B, Page B-6

The application states that "there appears to be general consensus that properly structured incentive based regulation can yield superior results to traditional cost based regulation". The Intervenors represented by this Information Request which include industrial customers, gas marketers, the HVAC industry, the greenhouse growers and flower growers industry have consistently raised concerns with respect to the appropriateness and effectiveness of PBR as opposed to traditional cost based regulation. The failure of Terasen to achieve consensus around a PBR proposal since the original 1998 to 2001 term would support this lack of consensus. The extensions arrived at through the withdrawal of what was originally a 17% rate increase for 2002 and now the review and establishment of a base for 2003 have had nothing to do with PBR proposals in the view of the Intervenors.

8.1 *Please explain and justify Terasen's assertion that "general consensus" has been arrived at (i.e., how many stakeholders agreed, how many disagreed?*).

<u>Response</u>

As discussed in response to LMLGUA et al Question 15.1, it is widely accepted by governments, regulators and regulatory experts across North America that properly structured incentive based ratemaking yields superior results to traditional cost based ratemaking. This is also recognized in Bill 40 that amends the *Utilities Commission Act.* The amendments will allow the Commission to use mechanisms, formulas or other methods of setting rates and may order that a rate so derived is to remain in effect for a specified period.

Most stakeholders that have engaged in discussions with Terasen Gas have indicated support in principle for PBR. However, the challenge has been how to develop a model that best meets the varying interests of stakeholders. Terasen Gas believes that the proposed PBR Plan satisfies the interests of all stakeholders and is an appropriate and effective model for establishing revenue requirements for 2004 - 2008.

8.2 *Terasen states that based on discussion with stakeholders, Terasen believes that an opportunity exists which would enhance the 1998 to 2001 PBR plan in order to establish stronger capital incentives able to deliver benefits approaching to those delivered through a price cap while retaining the simplicity of the formula based cost driver model is well understood in the British Columbia regulatory environment and one that is delivered value to customers and the Company. Please describe what discussions have occurred and with which stakeholders*.

Response

Terasen Gas has been engaged in on-going dialogue with many stakeholders and customer representatives over the last several years to help develop and refine the regulatory model. Stakeholders advised the Company that ways needed to be developed to enhance the Company's focus on capital spending during the negotiation of the 1998 – 2001 PBR. Discussions continued throughout the past PBR during the Annual Reviews and during stakeholder meetings leading to the development of the DRSM and most recently in preparing the current Application.

9. Tab B, Page B-6

Terasen states that it is proposing "a multi-year PBR plan that is more comprehensive" than the existing plan. Please described how the proposed plan is more "comprehensive".

Response

The most significant feature of the proposed PBR that makes it more comprehensive than the 1998 - 2001 PBR Plan is that the capital formula and incentive apply to all capital spending specifically, Category B and CPCNs. These items were not included in the 1998-2001 PBR. Terasen is also proposing improved SQIs and a mechanism to ensure continuing incentives to pursue efficiencies throughout the term of the agreement.

10. Tab B, Page B-7

Terasen states that "the key plan elements include 50/50 sharing between customers and the Company achieved efficiencies (after paying for restructuring costs) beyond those already imbedded in the O&M and Net Gas-Plant In-Service Formula;"

10.1 *Please describe how the approved rate of return of Terasen combined with financial incentives to management and executives for performance does not already incent Terasen to pursue those efficiencies*.

Response

The Company's allowed rate of return is established pursuant to the Commission's automatic ROE adjustment mechanism. The *Utilities Commission Act* requires that public utilities be afforded a reasonable opportunity to earn a just and reasonable return on the investment in utility assets. The traditional rate base/rate of return methodology provides an incentive not to take risks associated with new initiatives since the Company cannot capture benefits beyond its allowed return and may suffer from disallowances if the new initiatives do not achieve the benefits forecast.

In the absence of a mechanism that allows the Company an opportunity to capture over time benefits generated from investments in efficiencies, the Company would not be in a position to earn its allowed return because it would incur costs in one period (thereby reducing its return) and would have no opportunity to recover those costs in subsequent periods because the benefits would be provided to customers.

10.2 Please provide the latest "employee score card" which sets out how bonus and incentive pay for employees is allocated based on priorities of Terasen.

Response

Terasen Gas Inc. 2003 Scorecard

	Weight	
CUSTOMER		
O&M and Capital Expenditures	**15.0**	• Given that we are a regulated utility which is allowed to recover prudently incurred costs in our rates, effective management of costs is an important customer scorecard measure.
Customer Survey Score	**10.0**	• This measure includes residential, commercial, builders and developers. Based on an index score derived from surveys customers' opinions of Terasen and services we provide.
Customer Process	**7.5**	• Customer Process addresses our success in acquiring and maintaining customers.
Order Fulfillment	**7.5**	• A customer-focused process that allows us to receive, process, dispatch, install and close a new customer's order for gas service in a quick, safe, and efficient manner.
FINANCIAL		
Share Earnings (EPS)	10.0	• Shareholder value created when Terasen Inc. exceeds investors' expected rate of return. Currently Terasen Inc. dividends yield approximately 4%, earnings growth of Terasen Inc. must deliver 6% to achieve shareholders' expected returns (low risk returns of at least 10 %). • Terasen Gas Inc. now accounts for more than 50% of Terasen Inc.'s earnings, key role in this measure.
Utility Earnings	25.0	• Current strategy to meet earnings growth targets involves improving operational efficiencies, expanding our core competencies and broadening sources of revenues and earnings in all companies.
SAFETY		
Vehicle Accidents	5.0	• In order for Terasen to be successful, we need to continue to improve safety performance.
Lost Time Injuries	5.0	
Wellness	5.0	• Wellness is a new measure for 2003. The focus is to promote improved attendance at work for employees. This measure is a composite of annual days lost per employee for sickness, paid medical appointments, days lost due to injury, and child sick leave.
Public Safety		*Important factor with customer satisfaction and earnings implications. Refer to SQI's.*
PROCESS		
Meter to Cash	10.0	• Process redesigned in 2002 to improve collections & reduce bad debts & write-offs. Target to have Rate 1, 2 & 3 customers' Bad Debt experience at 0.46% of billed revenues
	100	

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11. Tab B, Page B-7

Terasen states the "the key plan elements include a continuing incentive to invest in efficiencies throughout the term of the plan". This matter was discussed in some detail in the Workshop dated May 15, 2003. Significant concerns arose with regard to whether Terasen should be able to have customers pay for plans which result in benefits to the Company post-term of the PBR. Those concerns were not effectively addressed by Terasen in the Workshop.

11.1 *Please explain how this initiative offers benefit to the customers*?

Response

As was discussed during the May 15 workshop and in the Application, the inclusion of a continuing incentive that provides the Company with ongoing benefits is beneficial to customers because it provides the Company with an ongoing incentive to undertake initiatives to generate efficiencies late in the term of the PBR. Without an end of term or phase out mechanism the Company would be "disincented" from investing in efficiency initiatives since it would be expected that the level of expenditures approved after the end of the PBR term would be reduced to the actual levels achieved (causing any benefits created by the efficiency initiatives to be realized only by the customers) thereby resulting in the Company not having the opportunity to recover its investments in efficiency initiatives made in the later years of a PBR period.

By allowing the Company to retain a portion of the benefits created late in the PBR term for a period of time extending beyond the PBR term, the Company will be incented to continue to pursue such efficiency initiatives and create more benefit opportunities for Customers than it otherwise would be in a position to do. During the phase out period the customers will receive part of the benefits, and upon completion of the phase out period the customers will receive all of the benefits. Accordingly, it is in the interests of customers to encourage the Company to continue to aggressively seek efficiencies during the whole of the PBR period.

11.2 *At the Workshop on May 15, 2003 Terasen indicated that in the later years of the last PBR term they did not make investments in efficiencies as a result of the termination of the PBR plan. Please specifically identify what initiatives were not undertaken by Terasen in the last PBR period as a result of the absence of an extension of the benefits of the PBR term to Terasen*.

Response

In late 1997 the Company undertook a major restructuring initiative as was discussed in the 2003 Application resulting in significant O&M savings in subsequent years. In addition during the term of the last PBR the Company implemented major IT systems to assist it in achieving productivity requirements and incremental savings. The Company had 3 years in which to recover such investments under the original term of that PBR. In the final year of the term, the Company secured a one year extension to the original Agreement and during the extension period embarked on discussions regarding a new multi-year PBR.

The Company did not undertake a second round of restructuring or embark on additional IT infrastructure initiatives to further reduce operating costs, because it would have entailed incurring restructuring costs in the last year of the PBR which the Company would have had no opportunity to recover.

There was little time to pursue such initiatives in any event due to the fact that the Company's priorities were focused on running the day to day operations to deliver safe, reliable service to customers and in pursuing a renewed regulatory settlement.

Please also see the response to Question 18.2 below.

12. Tab B, Page B-7

12.1 *Please describe how Terasen sees the mid-term assessment to review how the plan is working being conducted. Is this a full public hearing, an NSP process*?

Response

The mid-term assessment review will be an expanded Annual Review in the third year of the five-year term. As indicated on Page C-18 of the Application, the mid-term assessment review will be conducted to examine if any one (or more) particular element of the PBR Plan appears to be inducing unintended outcomes or deterioration of service quality and to determine if the results of operating under the PBR Plan have resulted in financial distress. It is intended that the participants in the mid-term review will collaborate to find solutions to any identified problems. Thus, the resolution of problems, should any problems be identified, will be more akin to a negotiated settlement than a full hearing. If resolution is not achievable on certain problems, the matters will be referred to the Commission for determination. The timing of the mid-term assessment review (and third year annual review) will likely have to be advanced to a point earlier in the fall than the usual mid-November date from the previous PBR, especially if any problems arising are significant enough to involve consideration of the termination of the PBR Plan.

12.2 *Will Terasen file application materials for those annual reviews? If so, in what form*?

Response

Terasen Gas will file annual review materials pursuant to the terms of the negotiated settlement and BCUC order approving the settlement. The negotiated settlement document for the 1998 - 2001 PBR set out the information to be provided and the timing of the filing. Similar to the practice in the last PBR, the Company anticipates that annual reviews will be held in the fall and annual review information will be provided to the Commission and Intervenors several weeks before the annual review meeting.

13. Tab B, Page B-7, "Restructuring Funded Through Achieved Efficiencies not from Customers"

Please confirm that the efficiencies do not materialize as demonstrated in a measurable objective way, the costs will be paid for by the Shareholder of Terasen.

Response

The costs associated with O&M and Net Gas-Plant-In-Service that will be included in customers' rates will be those set by formula. Whether or not efficiencies materialize, the rates will be set through use of the formula. Efficiencies will be shared with customers through rate riders. Under the Company's proposal to recover restructuring costs prior to sharing, if the Company incurs restructuring costs and efficiencies do not materialize then the restructuring costs will be borne by the Company.

14. Tab B, Page B-8

Terasen states that "it is the Company's assessment of its year-to-year actual cost of service increases that would likely be sought through future annual revenue requirement applications in the absence of a PBR plan (the "Cost of Service" or upper line on the graph)". Please describe the assumptions that went into establishing this annual cost of service line.

Response

In developing the "Cost of Service" forecast the Company has made estimates for new costs that have been identified since the 2003 revenue requirements application that are identified in Tab E, pages E-5 to E-7.

Please refer to the response to BCUC Staff Question 11.3 for details of those costs.

15. Tab B, Page B-9

15.1 *Terasen states that "the experience of BC Gas as well as in other jurisdictions has established that PBR delivers significant value relative to traditional rate of return regulation". Please describe the latest information that Terasen has relied on in regard to other jurisdictions in order to support this statement*.

Response

Terasen Gas has had discussions with numerous local and international regulatory experts, business leaders, customer representatives, utilities, government officials, and regulators relating to the benefits of PBR over traditional cost of service regulation. The benefits of PBR are often discussed in regulatory courses and conferences. For example, the CAMPUT conference held in April 2003 included a discussion of the benefits of PBR over traditional regulation.

In the United States, many utilities at both the state and federal levels are under various forms of incentive ratemaking. In Canada, all of the major gas distribution utilities in Quebec, Ontario, Alberta and British Columbia are regulated using some form of PBR or incentive ratemaking. Similarly, the National Energy Board has endorsed incentive ratemaking for oil and gas pipelines under its jurisdiction.

In British Columbia, the support by the Provincial government for PBR is made clear in the Energy Policy which included the direction that:

> "The *Utilities Commission Act* will be amended to focus more on performance-based and results based regulation, including negotiated settlements, and to define effective consumer protection."

The broad acceptance of incentive ratemaking by governments, regulators, customer representatives and utilities in British Columbia and across North America testifies to the fact that properly structured PBRs deliver significant value relative to traditional cost of service regulation.

15.2 *Terasen states that "the benefits of PBR include lower delivery rates through achieved efficiencies, greater certainty in rates by establishing results based formulas and approved regulatory and administrative efficiency." In the recent revenue requirement hearing, a significant issue arose with regard to the level and quality of reporting, an oversight of Terasen in regard to the regulatory requirements. Terasen has indicated that they are working on correcting some of those mistakes. When does Terasen anticipate responding to each of the concerns raised by the Commission in the decision*?

Response

In its February 2003 Decision the Commission provided a number of directions to the Company. The Company's response to these directions is discussed at Tab E, pages E-1 to E-3 of the current Application, however only one of the Commission's directions related to reporting. That direction related to the Company's requirement to file annual Code of Conduct compliance reports. As indicated in the response to question 7 above, this report was filed in April of this year. The balance of the directions related to changes that are to be made prospectively which the Company has dealt with as indicated.

15.3 *In light of the incomplete response at this point, does Terasen accept that no further PBR settlement should be arrived at until all parties are satisfied that Terasen has responded to the failure to comply with reporting responsibilities during the last PBR period*?

Response

The Company has fully complied with matters relating to the last PBR period. The only ongoing matter is the separation of the Terasen Centre employee group study which is in progress and will be completed this year. The Commission in its Decision addressed the appropriate level of cost that Terasen Gas should bear relating to the support and services provided by this group and it is this base level approved for 2003 that would be used to determine the allowed costs for 2004 under the PBR formulas proposed.

Therefore the Company sees no reason why a new PBR settlement can not be concluded while the separation work is under way.

16. Tab B, Page B-10

Terasen indicates that the PBR plan offers enhanced benefits relative to past plans by extending the capital incentive to all capital including CPCNs. If Terasen does not pursue the CPCNs plan set out in the forecasts, will those costs be eliminated from the annual capital budget through the PBR term?

Response

No, the capital forecast information included in the Application, including amounts for CPCNs are the Company's best estimates of future costs during the proposed PBR period. Terasen Gas proposes accepting the risk of CPCNs including new CPCNs not identified in the Application materials. To the extent that the plan changes during the period, the Net Gas-Plant-in-Service formula will not be adjusted to reflect the changes, either up or down.

17. Tab B, Page B-10

Terasen states that while Terasen "believes these changes are improvements over past PBR plans, perhaps the most important benefit of PBR is that it ensures alignment between customer and company interests by encouraging innovation, customer focus and the on-going pursuant of operating efficiencies". Given that the Commission approves a return on equity on an annual basis which establishes a fair, just and reasonable return to the shareholder, why are further incentives required through PBR formula and revenue sharing initiatives to encourage innovation, customer focus and the on-going pursuit of operating efficiencies?

Response

The Company does have an incentive to encourage innovation, customer focus and the ongoing pursuit of operating efficiencies based on the normal operating risks it manages in pursuit of achieving its allowed rate of return. Normal operating circumstances always present unforeseen challenges and cost pressures and ongoing improvements and efficiency gains are required just to meet the allowed rate of return under traditional rate setting. However in the absence of a PBR arrangement, the Company has no incentive to put additional capital or resources at risk because there is no opportunity available to recoup its investment and be rewarded for the additional risk taken.

The incentives under the proposed PBR Plan provide a potential payback stream to recover the costs associated with undertaking additional risks and committing shareholder resources. The Company is not assured recovery of all such costs incurred even with the incentives in place as not all initiatives will provide the economic payback as originally hoped. Under the 1998 PBR Plan, it was not until the fourth year (i.e. the one year extension period in 2001) that the Company broke even on the investments it made in O&M savings at the start of that PBR Plan.

Please also see the response to Question 10.1 above.

18. Tab C

At pages C-1 and C-2 Terasen points out the concern with regard to "cost–based" cost of service regulation indicating that the "traditional mode of regulation puts the onus on the regulator to effectively 'pre-approve' investments in efficiency because the very muted opportunity for short term incentives is over shadowed by the strong cultural bias among employees to avoid risky initiatives that may be 'second guessed' and disallowed. Terasen believes that the responsibility for ensuring that economic incentives and efficiency gains are made should rest with the Company. This is best achieved through a multi-year PBR."

18.1 *Under the proposed incentive mechanism whereby efficiency gains first go to recover the expenditure of the Company, how does Terasen see those investments being approved such that the efficiency gain can be targeted to recover the costs incurred*?

Response

Please see response to Questions 4.1 and 4.2 above.

18.2 *Please described some of the "risky initiatives" which have not been pursued by Terasen in the past PBR term which might be pursued in the next two years assuming this PBR application is approved*.

Response

In its response to the BCUC IR No. 2, Question 29.2.1 in August 2002, the Company highlighted a number of initiatives that required a longer term payback period. These included:

- alternative excavating techniques

- trenchless technologies
- new core structure and job logistics
- retraining, cross training
- AM/FM for transmission plant
- electronic interchange with customers

The Company would also explore further restructuring opportunities, further operating integration with Terasen Gas (Vancouver Island), possible technology initiatives, new load building or other cost sharing opportunities. These might include further outsourcing or restructuring of operations or "back office" functions.

Examples of the above items might include:

- Automation of activities – i.e. investments in capital equipment to make it possible to replace manual corrosion readings and station pressure chart changing.

- Further investments in technology – mobile data dispatch –systems to eliminate duplication of data entry and closing functions currently performed in the back office.

- Preventive maintenance philosophy changes – optimize risk, cost, maintenance schedules – i.e. reduce scheduled meter exchanges, station operational checks, etc.

None of these items have been developed sufficiently to assess whether there is a reasonable business case to proceed. The February Decision provides no incremental funding to pursue such investigations. Further work would be undertaken in the context of a PBR as the incentive mechanism would allow the Company to offset these costs through the sharing of achieved benefits.

Please also see the response to Question 11.2 above.

19. Tab C, Section C-A-1

19.1 *Terasen proposes that "Leaks per kilometer of Distribution Mains" and "Number of Third Party Distribution Incidents" be removed from the Service Quality Indicators and classified instead as Directional Indicators. Since Terasen "believes it should be directed to find as many existing leaks as reasonably possible," how does this classification change improve Terasen's performance with regards to leak detection*?

Response

The measure was designed to reward a low number of leaks on the premise that a system with fewer leaks was in better condition than one with many leaks. Terasen policies and the new Preventative Maintenance (PM) system are all designed to find as many problems as possible and fix them. This will result in an increase in the number of leaks as attention is focused on upgrading problem areas. The result is a better system, but the measure would indicate otherwise.

Please also see response to BCOAPO Question 7.9.

19.2 *Indicator No. 2 (Percent of responses within 30 seconds by a person for an Emergency Call) and Indicator No. 3 (Percent of responses within 30 seconds by a person for a Non-Emergency Call) only track how quickly the telephone is answered. In Terasen's opinion, is there a way in which to track how quickly problems are solved (as opposed to the telephone answered)*?

Response

These measures are standards that Terasen Gas tracks in its contract with CustomerWorks. For non-emergency call resolution, a performance measure may not be meaningful as there is a large diversity in the issues involved. Some issues such as billing questions may be resolved with one telephone call, while other issues such as meter disputes may require multiple site visits. Terasen Gas does have the capability to track response time to emergency calls such as hit lines.

19.3 *Who is responsible for measuring Indicator No. 5 (Percent of Customer Bills Produced Meeting Activity Criteria)? Will it be necessary for customers to provide information regarding billing discrepancies to both Terasen and to CustomerWorks? Who is responsible for the "input data"? If invoices are adjusted because of incorrect input data, the result to the customer is the same. From the customer's point of view, the billing sub-measure should read "Percentage of bills accurate"*.

Response

CustomerWorks is responsible for measuring this indicator and the sub-measures. It is only necessary for the customer to alert CustomerWorks to any billing discrepancies. Concerning the issue of responsibility for input data, this wording was constructed to reflect the reality that CustomerWorks is not always responsible for input data and hence should not always be penalized for incorrect bills. For example, a customer would be responsible, in the case of a PST exempt strata, to inform CustomerWorks that it is tax-exempt. Failing CustomerWorks knowing this and the customer not telling CustomerWorks, it should not be CustomerWorks responsibility to bear penalties for input data in this case.

19.4 *Customers would find it meaningful to see a service quality indicator with respect to measurement data. Percentage of accurate daily reads with the target percentage being 98% would be a meaningful service quality indicator. Would Terasen include this SQI*?

Response

Terasen Gas is prepared to look at SQIs relating to daily measurement data. The percent accuracy of 98% may be achievable at a certain point in the future, but it is not achievable today. Further, Terasen Gas is of the opinion that the measures it has informally agreed to track with certain marketers have enabled these customers to adequately do business on Terasen Gas' system – especially given the current balancing tolerances. Terasen Gas has made large steps in improving its meter accuracy over the past year and is committed to continuing this improvement. The Company is prepared to commit to more realistic measures in the near term with an eventual raising of standards as system improvements are achieved. Terasen Gas is also open to shippers who require a higher standard of measurement paying for the increased O&M expense associated with such improvements.

20. Tab C, Page C-2

20.1 *Described how "unit cost economy of scale may be realized over time from the acquisition of Centra" and how such economies of scale may be factored into the proposed PBR application*.

Response

There may be opportunities to more closely integrate operations of Terasen Gas (Vancouver Island) and those of Terasen Gas. In that event, common management practices and systems may be used to reduce operating costs for both companies. It is anticipated that significant investment in systems and data conversion would be required to achieve tighter integration and related efficiencies. The benefits to accrue to the Company would be in the form of cost recovery and reduced O&M. The benefits to the customers would be through the sharing mechanism and through the reduction in costs at the end of the PBR period.

20.2 *Will those efficiencies go to the benefit of Terasen's customers or Centra's customers*?

Response

It is anticipated that benefits will accrue to the customers of both companies over time, however, the amount and split will be determined by the circumstances as they unfold. For example, the Company may be able to provide additional management of operations activities and recover costs through cross charges lowering the total O&M of the

Company. This creates a benefit that would accrue through the sharing mechanism to the customers of Terasen Gas.

Terasen Gas Vancouver Island customers would achieve benefits through lower operating costs achieved by Terasen Gas Vancouver Island when their costs are rebased in their next rate setting proceeding.

20.3 *To what extent will those efficiencies be shared with the shareholder as opposed to the customers*?

Response

The Company is proposing 50:50 sharing of all efficiency gains subject to the proposal for the recovery of restructuring costs prior to sharing.

21. Tab C, Page C-5(d), Sharing Mechanism

"A sustained (two year average) return of 200 basis points above or below the allowed ROE triggers the provisions of the Off-Ramp." In the event that Terasen earned well above the allowed ROE one year, what mechanism would be put in place to ensure that the Company did not simply increase expenses in the following year in order to ensure the two year average did not hit 200 basis points? Does the two year average refer to two consecutive years?

Response

The Company has proposed annual reviews to report on operations and project results to the end of the current year as well as a more comprehensive mid-term review. Stakeholders and the Commission are in a position to challenge the Company's performance level and activities. It would be readily apparent if the Company was gaming in order to avoid creating an off ramp relating to achieving excessive earnings. The Company is supportive of PBR and will endeavour to ensure an ongoing mechanism that will satisfy all parties.
The two year average refers to 2 consecutive years.

22. Tab C, Page C 5(f), Exogenous Factors

Does Terasen anticipate any revenues associated with the unbundling initiative?

Response

The business model under development for the unbundling initiative does not contemplate or identify new or additional revenue opportunities for Terasen Gas. However, to the extent that the unbundling program is successful as expected, Terasen Gas will realize a reduction in revenues associated with gas commodity sales.

Furthermore, all of the costs associated with developing, implementing, operating and maintaining the program, will need to be recovered in rates, which will result in increased revenues. The level of expenditures and the cost recovery treatment is subject to approval by the Commission. Estimates of the capital and operating and maintenance costs are currently under development and will be included in Terasen Gas' Unbundling submission to the Commission on July 18, 2003.

23. Tab C, Page C 5(i), Mid-term Assessment Review

Who undertakes this review? Would Terasen be amenable to having a third party undertake an audit as part of the review process?

Response

The Mid-term Assessment Review would be undertaken by the Company, stakeholders and Commission Staff. As discussed at the November 2002 hearing, the Company does not believe having a third party undertaking an audit as part of the review process would be cost effective as the scope of the mandate would be difficult to control making it cost-prohibitive. The Company's financial statements are audited, Annual Reports are filed with the Commission and the Commission has powers to order audits of operations if they have any concerns. Therefore the Company would not support third party audits as part of the review process.

24. Tab C, Page C 5(j) Off-Ramps

The Ontario Energy Board Performance Based Regulation Implementation Task Force stated that "Caution is advised because the use of exit ramps often leads to some 'gaming of the system' so as to either avoid or to trigger exit ramps." Please comment.

Response

Please see the response to Question 21 above. In Ontario the OEB does not conduct an Annual Review process as was included in the 1998 - 2001 PBR and as proposed in this Application. The ongoing Annual Reviews and the inclusion of a Mid-term Assessment combined with the Company's desire to sustain positive relationships with stakeholders provide safeguards to ensure that no 'gaming of the system' will take place. Further, the Company believes the existence of an "Off Ramp" condition should trigger a process that might result in the continuation of the PBR with appropriate alterations as reviewed with the stakeholders and approved by the BCUC.

25. Tab C, Page C 5(k) Pipeline Integrity Cost

"If a portion of the expenditures forecast to be funded under this plan is required to be treated as an O&M expense, rather than a capital expenditure, then an adjustment to rates is necessary to compensate for that additional O&M expense." Who would require a portion of the expenditures to be treated as O&M?

Response

The quotation in the question is in item "k" on page C-19. The Transmission Pipeline Integrity Plan (TPIP) is the subject of a CPCN application to the Commission, and to date the costs associated with the TPIP have been treated as capital expenditures. The reference in the quotation to "is required to be treated" was meant to be a reference to the Commission requiring that the TPIP expenditures, or a portion thereof, be treated as an O&M expense rather than a capital expenditure.

Please also see the response to Question 33 below.

26. Tab C, C-6

26.1 *Please provide some examples of the more "complex, aggressive and costly changes" to business operations contemplated by Terasen*.

Response

Please see the response to Questions 11.2 and 18.2 above.

26.2 *The Company has had approximately three years to plan this PBR mechanism and it is assumed some specific initiatives are contemplated at this point in time. What are the three most significant initiatives that Terasen would pursue under the proposed PBR plan*?

Response

As was stated in the May 15 Workshop, the Company does not have specific plans for the implementation of initiative of the magnitude taken under the last PBR. There are diminishing returns available for similar efforts. In fact as was stated, it is expected that the majority of new initiatives and improvements will be more "grass roots" as opposed to being top down or related to large initiatives as in 1997/1998.

Please also see the Response to Question 26.1 above.

27. Tab C, C-8

Terasen states that "the Company witnessed significant progress in this cultural change under the 1998 – 2001 PBR plan and believes the proposed PBR plan will build on such a new culture". Please comment on to what extent the individual employee incentives implemented by Terasen affected this culture versus the PBR plan.

Response

It is difficult to separate the extent to which individual employee incentives implemented by Terasen affected this culture versus the PBR plan because individual incentives are structured to achieve alignment with the PBR. The PBR provides an overall framework for establishing the culture and individual incentives are structured to reinforce these objectives.

28. Tab C, C-8

28.1 *Terasen proposes that the GCRA, RSAM and GSMIP mechanisms will continue to operate as they have in the past. The Company supports exploration of such ideas in the negotiated process. What proposals does Terasen have in this regard*?

Response

The GCRA, RSAM and GSMIP mechanisms are not part of this Application and would not be affected by the PBR. Terasen Gas does not envisage any changes to these mechanisms. An item that was discussed at the Workshop was the potential for introducing load building programs to help offset future reductions in use per customer which would increase revenue requirements. It was identified that a separate mechanism would be required to better align the interests of the Company and customers because any increases in revenue would otherwise be captured by the RSAM. The proposal relating to load development is discussed in more detail in response to Question 29.

28.2 *Given the number of flow through expenses that are not affected by incentive mechanism and are now not subject to annual rate of return reviews, would it not be reasonable to assume that Terasen is now a lower risk utility than that which was determined in the initial rate of return reviews undertaken by the Commission*?

Response

The risk profile of Terasen Gas is not lower under the 2004 - 2008 PBR than under either the previous PBR or annual revenue requirement applications. The cost of service items subject to flow-through and/or deferral treatment are essentially the same as those the Company had in place during the 1998 – 2001 PBR Plan. The new items for deferral treatment, pensions and insurance, are both areas where there has been significant volatility increases in recent years. Under the proposed PBR formula the Company is taking on additional risk with respect to capital expenditures since all base capital and CPCNs have to be managed within the levels allowed by the formula.

29. Tab C, C-15, Greater Through Put Volumes

Please provide examples of the proposed "new load building programs".

Response

Examples of the proposed "new load building programs" include increasing the use of natural gas appliances in homes where natural gas delivery service is already available. Research available suggests that there is an opportunity to increase the use of natural gas appliances of existing Terasen Gas customers. The market research indicates that the percentage of Terasen Gas' customers using natural gas for water heating, clothes drying and cooking is low when compared to that of natural gas customers in the United States, particularly for clothes drying and cooking.

Terasen Gas' marketing strategy will include seeking partnerships where possible with third parties such as Natural Resources Canada, in order to gain access to additional financial and technical resources to use to encourage consumers to purchase and use more natural gas appliances. With the loss of the historical price advantage of natural gas to electricity, changing the mindset of customers to natural gas use is paramount in order to ensure natural gas remains a competitive fuel. The qualitative attributes of using natural gas such as lifestyle and environmental benefits need to be brought to the forefront of consumers' minds. Generating primary demand with consumers for natural gas without the benefit of a price advantage is a risky, costly and long-term undertaking.

Furthermore, alliances with third parties such as distributors (i.e. manufacturers, wholesalers, retailers) and contractors will also be sought to further "influence" consumers' purchase decisions regarding natural gas appliances. The HVAC community will be an effective distribution channel to promote the continued and increased use of natural gas. For the HVAC community, Terasen Gas' marketing efforts to increase natural gas appliance use will likely generate new revenue opportunities in installation and service work for its members.

30. Tab C, C-17, Service Quality Indicators

30.1 *Please explain how any of the service quality indicators are relevant to industrial customers*.

Response

All the proposed indicators are relevant to industrial customers as this customer group should be interested in safe, reliable service with accurate and timely billing. There is also a real cost impact if Terasen Gas does not meet the performance criteria, for example measurement errors result in loss of revenue, emergencies not properly handled result in loss of service and possible high repair and recovery costs, missed meter exchange appointments mean return visits and potential Industry Canada penalties.

If there are other indicators that would address specific needs or concerns of industrial customers beyond the proposed ones, Terasen Gas remains open to adding these to the list.

30.2 *Please explain financial impacts on the Company in the event service quality indicators are not met*.

Response

The Response to BCUC Staff Question 1.10.6 addresses the proposed treatment of incentives in the event service quality indicators are not met. It is also proposed that if Terasen Gas fails to meet the SQI benchmarks, a review of the performance levels would result. The review would determine the cause of the decline and ascertain whether the deterioration is the result of the PBR plan. The PBR plan also provides for Off-ramps should there be a sustained material degradation of service quality.

Please also see the response to Question 32 below.

31. Tab C, C-18

Please describe the mid-term assessment review in terms of who will be involved, what materials will be provided and how customer shareholders and the Commission would participate.

Response

The Mid-term Assessment Review would be undertaken by the Company, stakeholders and Commission Staff. In addition to the normal Annual Review presentations, the Company would prepare an updated forecast for the balance of the PBR term and a review and assessment of how the mechanism has worked during the first half of the term and the Company's operations during that period. This material would be circulated prior to the Workshops and a more extensive Q&A period would be undertaken.

The mid-term review could include a provision for parties to make submissions on their assessment of how the PBR Plan has been working. This may result in further discussion concerning whether or not adjustments to the PBR Plan are desirable for the balance of the term, including an extension of the term if parties agree this is warranted.

Please also see the response to Question 12.1.

32. Tab C, C-18

Please define "serious degradation" of service quality indicators.

Response

The term "serious degradation" is used on page C-18 in reference to the Service Quality Indicators. As set out on page C-18, it is proposed that a serious degradation of the SQIs would trigger a regulatory review.

Terasen Gas does not believe that "serious degradation" can be defined in a manner that would foresee all circumstances. For example, a fire or other unexpected event might lead to a significant but short-term degradation of certain SQIs. Such a circumstance might not be considered as a serious degradation while a lesser but persistent long-term degradation of the same SQIs might be regarded as a serious degradation.

Terasen Gas has proposed a suite of SQIs. Terasen Gas proposes that if its performance on a number of the SQIs materially departs from the benchmarks for those SQIs then an Intervenor, or the Commission, could seek an examination of the Company's performance through a regulatory review. Following that review, if the Commission were to determine that there had been a serious degradation of the SQIs for reasons other than something that was short term or unexpected, then the Commission could order that the PBR Plan be brought to an end.

33. Tab C, C-19, Transmission Pipeline Integrity Plan

Please describe why there should be an adjustment in rates if a portion of the transmission pipeline integrity plan is to be captured as an O&M expense instead of a capital expenditure.

Response

The TPIP expenditures have been treated as capital expenditures to date, and the current rates of customers reflect that treatment. In the absence of a PBR Plan if the TPIP expenditures, or a portion thereof, were treated as O&M rather than capital, then the result would be an increase in the rates of customers since O&M has an immediate dollar for dollar impact on rates while the impact of capital expenditures is spread over time.

It is proposed that during PBR Plan the O&M and Net Gas-Plant-in-Service components of rates will be determined by formula. The proposed formula approach to rate setting would fail to recognize the different impact of O&M vs. capital treatment of the TPIP expenditures without the inclusion of the specific provision for the adjustment in rates. The effect on the rates of customers under what is being proposed for TPIP expenditures is the same as what the effect would have been in the absence of a PBR Plan.

Please also see the response to Question 25 above.

34. Tab C, C-19

Please set out all deferral accounts and deferred charges previously approved which are intended to continue through this PBR term.

Response

The listing of existing deferral accounts included in the PBR and their duration during the five-year term is found in Section H, Tab 3, Pages 6 to 6.20. Additional deferral accounts may occur, beyond those shown in that section, for items that are sought in this Application but for which there is no current balance. Pension costs, insurance costs and tax changes are examples of these. Also, a deferral account pertaining to the unbundling process has been approved, as indicated in BCUC Letter No. L-14-03. The manner of inclusion of this unbundling deferral account in rates will be determined in the unbundling process.

35. Tab C, C-20

The application indicates a second scenario where cost of service pressures would see incremental, additional expenditures of $5 million annually. Please explain the rational behind this $5 million per year increase in cost of service.

Response

Please see the response to Question 14 above. The actual costs brought forward in annual cost of service applications over the next 5 years if PBR is unsuccessful may be higher than $5 million. These are only the items that have been identified since the November 2002 hearing.

36. Tab C, C-21

Please explain Terasen's rationale for applying a 2% CPI increase to its capital expenditure plans for 2004 to 2008.

Response

Capital expenditures are subject to inflation for similar reasons as other cost of service elements such as operating costs. A significant portion of the Company's annual capital expenditures are for the labour costs of employees. The annual wage increases in the collective agreements with bargaining unit employees are greater than 2% over the next several years. The costs of other components of capital expenditures such as materials may be rising at less than 2% per annum. On average 2% is a reasonable inflation rate to apply to capital expenditures over the five-year period.

Please also see the response to BCOAPO Question 2.1.

37. Tab C, C-23

In the 1998 – 2001 PBR Terasen was required to meet productivity factors of 2%, 2%, 3% and 1% in each of the four years of that plan respectively. In this plan Terasen is proposing to meet productivity factors of .75% as well as earn a return on investment in efficiency. Why should customers not expect efficiency gains equivalent to those achieved by Terasen in the 1998 – 2001 PBR proceeding?

Response

Please see response to BCUC Staff Question 1.1.

38. Tab C, Pages C-23 and C-24

Pages C-23 and C-24 identify initiatives that resulted in the productivity improvements in the 1998 - 2001 PBR period. What productivity improvements has Terasen forecasted to undertake to achieve the .75% proposed in this application?

Response

The Company has not forecast any specific productivity improvements but would look at initiatives such as those described in the responses to Questions 11.2 and 18.2 above as well as ongoing process improvement initiatives and streamlining of operations.

The Company believes that with the incentives available under the proposed PBR Plan that it will be able to take on reasonable levels of risk and make investments in efficiencies throughout the term that would allow it to achieve operating efficiencies supporting a 0.75% adjustment factor and hopefully to achieve incremental benefits beyond that level that would be shared with customers.

39. Tab D, Capital Requirements

Please explain how the CPI increase is applied to capital for the term of the proposed PBR.

Response

The capital requirements are forecast first in current dollars using the activity levels, planned projects and cost drivers applicable to the particular portion of capital expenditures. The current dollar estimates are then inflated by 2% per year to the particular year in which the capital expenditure is forecast to occur.

40. Tab E, Page E-2

40.1 *Please provide a copy of the Score Card Objective presently utilized by Terasen*.

Response

Please see the response to Question 10.2 above.

40.2 *Please provide a copy of the DSM evaluation which was filed in April of 2003*.

Response

A copy of the DSM report filed in April 2003 is attached as Appendix B.

40.3 *In the revenue requirement proceeding there was discussion around the marketing expenses of BC Gas. Please indicate what amount of the expense related to the name change of BC Gas Utility to Terasen is included in the 2004 revenue requirement and in each of the years of the PBR*.

Response

No costs associated with the name change are included in the 2004 revenue requirement or for the balance of the PBR term. The name change costs were paid for by Terasen Inc. not the Utility. None of the marketing expenses discussed in the revenue requirement proceeding related to the name change.

The only costs incurred directly by Terasen Gas were for normal course replacement of assets. Those assets being replaced in the ordinary course will naturally have the new name and logos. All incremental costs will be or have been covered by Terasen Inc.

41. Tab E, Page E-3

Terasen states that "since the time of the Company's 2003 revenue requirement application, the Company has identified a number of new cost pressures related to the Company's operating costs which could result in material changes from the forecasted O&M costs filed in the 2002 revenue requirement application". Terasen quotes at page A-2 of its application the following quote from the Commission's Order of November 12, 2002:

> *"By establishing a thorough public record for a 2003 base year, the Commission anticipates that an efficient negotiated settlement process on a future multi-year performance based rate making application may follow in 2003."*

41.1 *Is Terasen anticipating that the negotiated settlement process should enable Terasen to increase its operating costs above those approved by the Commission in the above-noted decision*?

Response

No, this process establishes a mechanism for setting rates during the term of the PBR period. Rates for 2003 will not change as a consequence of the NSP and the introduction of a PBR Plan for 2004 - 2008. The mechanism will establish rates for 2004 and beyond with formulas that establish recoverable levels of costs for controllable items. 2003 is the base level of costs for the formula related items; 2003 costs and rates are not being re-opened as part of this Application.

41.2 *Can Terasen identify what the new cost pressures are that they are referring to at page E-5 of the application*?

Response

Yes, they are described at pages E-5 to E-7. Please see also response to Question 14 above.

42. Tab E, Page E-6

42.1 *What marketing and customer care costs pertain to the name change and rebranding undertaken by Terasen after the revenue requirement application concluded*?

Response

None. Please see response to Question 40.3 above.

42.2 *There was a significant increase in marketing expenses in 2003. Would that expense not be reduced as a result of the completion of the rebranding project*?

Response

No, the rebranding costs were not included in the 2003 budget. In fact some costs for 2003 were inadvertently left out as discussed in the response to Question 14.

43. Tab E, Page E-6, Employee Compensation

Given the relative attractiveness of compensation for employees who fall within the category of employees eligible for stock options as paid for by the customers, would it not be appropriate for any further incentives to management and staff be paid for out of shareholder's share in any efficiency gains achieved by Terasen during the PBR period?

Response

Opportunities for incentive compensation are only available if warranted by individual and corporate performance. Under PBR, achieving efficiency gains while maintaining safe, reliable service and performance on service quality indicators will be one of the key objectives of the Company. These objectives can only be met through the effort of employees. Incentives help align employee objectives with corporate objectives by rewarding employees for the achieved business results which include the pursuit of efficiency gains.

Efficiency gains are shared 50:50 with customers during the term of the PBR and are permanently embedded in future rates through rebasing at the end of the PBR term. Since customers benefit throughout the term and thereafter from the efficiencies, it is appropriate that the total employee compensation including incentive pay be included in the O&M and variance from forecast shared 50:50 between the Company and customers.

44. Tab E, Page E-6, Pension Expenses Related to Pensionable Bonuses

44.1 *See above question on employee compensation*.

Response

Please see above answer on employee compensation.

44.2 *On page E-39, Terasen states "the agreement with CustomerWorks places a constraint on cost pressures after 2003 that should hold future cost increases to well below the forecast rate of inflation". Why would Terasen not have a higher level of certainty around the impact of this contract on cost pressures*?

Response

The existing contract with CustomerWorks expires during the term of the PBR period as it was for a 5 year period commencing in January 2002 and will expire at the end of 2006. The renewal provisions provide for cost adjustments below the level of inflation, however, scope changes that may be required during the term of the contract and which are not known at this time may arise and would be brought before the Commission for approval. These would be absorbed by the Company during the term of the PBR.

It should be noted that any costs and/or scope changes required as a consequence of unbundling directions would not be absorbed by the Company within the formula. They would be recoverable in rates as approved by the Commission.

45. Tab F, Page F12 – 8, SCP Third Party Revenues

45.1 *"BC Gas has forecast the net accumulation in the SCP mitigation deferral account from this issue to be $4.4 million ($6.6 million of lost revenues less $2.2 million of mitigation revenues)." Since the Commission determined that the net amount of the deferral account will be "determined by way of a future Commission order", what factors have changed such that Terasen is again seeking approval when in December the Commission chose to defer any decision regarding deferral account treatment*?

Response

When the Commission issues its decision on the Company's 2004 – 2008 Application it will be "by way of a future Commission order" and will therefore be consistent with the December letter. In addition to this, the Company's overall request arising from the cancellation of the PG&E contract is reasonable with respect to the treatment of SCP 3rd Party revenues and amounts deferred . The amortization commences at the same time the full benefit of the extra revenue from the replacement contract is included in the cost of service. Since the additional revenues from the replacement contract are greater than the annual amortization, the net effect is to reduce annual revenue requirements by more than $2.5 million.

45.2 *"Beginning in November 2004, monthly demand revenue is forecast to increase to over $900,000, reflecting the revised agreement replacing the capacity held by PG&E." Is there any contribution from the utility embedded in the $900,000? (i.e. for the incremental 10,000 Mmcfd that is not contracted as of November 1, 2004)*?

Response

There is no contribution from the utility embedded in the $900,000. It represents the third party SCP mitigation revenues only.

45.3 *In the marketplace, what is the approximate value of 52,500 Mmcfd of peaking capacity at Huntingdon*?

Response

The value of a peaking option delivered at Huntingdon in any given year will vary depending on market availability, market pricing and term of peaking option. The question specifically mentions "peaking capacity at Huntingdon" so it is assumed that the question is referring to having the rights to pipeline capacity from AECO, Kingsgate or Station#2 to Huntingdon for any 15 days during the winter. This is not a typical product offered by the marketplace and especially at Huntingdon. The SCP peaking arrangements were unique and have relatively complex call rights and pricing structures that would be different than the question considers. Due to the vast amount of variables to consider in any option valuation Terasen Gas would require more specific information around terms and conditions to provide further valuation information.

46. Tab G, Page G-4, Transfer Pricing Policy

It is the understanding of Commission staff that when offering products it is only necessary for the utility to cover its costs, not be profitable. What is to stop Terasen from offering products at cost (but under market) such that other market participants are disadvantaged?

Response

The Transfer Pricing Policy requires the Company to sell its services at the greater of the market price or fully loaded costs. Therefore, the Transfer Pricing Policy restricts the Company from offering products or services for less than market prices. Furthermore, in contrast to cost of service regulation, the incentives under PBR directly incent the Company to charge the highest price possible and thereby maximize revenues in order to offset cost pressures.

47. Tab G, Page G-4

Please indicate when Terasen will file a complete report with the Commission on the separation of BC Gas Inc. pension salaries and expenses from those of BC Gas Utility.

Response

A plan for the separation of pensions, salaries and expenses as directed in the February Decision has been developed and the specific steps of the plan are being determined. The completed report outlining the details of the plan will be finalized by the summer and will be filed with the Commission by not later than August 31, 2003. The actions in the plan will be implemented on or before January 1, 2004.

48. Tab G, Page G-5

48.1 *Please provide a copy of the annual compliance report for 2002 filed April 11, 2003*.

Response

Attached as Appendix C is a copy of the annual compliance report for 2002, filed on April 11, 2003.

48.2 *Please provide copies of the briefings on the code of conduct and transfer pricing policy which were provided to employees in March of 2003*.

Response

Please refer to Appendix D, which includes a PowerPoint presentation entitled “Cross Charging”.

49. Tab G, Page G-7

Please provide a copy of the deferred charge balances and amortization to be included in the revenue requirement for 2004.

Response

The forecast of deferral accounts and amortization included in the revenue requirement for 2004 is found in Section H, Tab 3, Pages 6.7 and 6.8. Under the PBR the forecast of deferred charges and amortization will updated in the fall for the Annual Review.

50. Tab G, Page-7b, B.C. Corporation Capital Tax (CCT)

"BC Gas' historical filing position has been a reasonable and defendable one, and as such, customers have benefited from the lower tax liabilities calculated in prior years." Is Terasen able to provide a comparison of monies saved by customers in years prior to 1995 versus potential liabilities, interest and penalties, plus legal costs, for the period 1995 through to 2002?

Response

The table below shows the estimated savings of $380,000 that would have been the incremental CCT amount paid for 1992-1994 had the Company been assessed on the CIAOC in those years.

	CCT
1992	$105,000
1993	110,000
1994	165,000
	$380,000

The table below lists the estimated CCT liability, interest and penalties for 1995-2002 based on the challenge to the filing position taken by Terasen Gas.

	CCT	Interest	Penalty	Total	
1995	$146,428	$102,111	$0	$248,539	Actual reassessment; paid April 2002
1996	195,019	144,663	0	339,682	Actual reassessment; paid February 2003
1997	195,000	120,000	0	315,000	Estimate
1998	260,000	130,000	0	390,000	Estimate
1999	315,000	125,000	0	440,000	Estimate
2000	330,000	100,000	0	430,000	Estimate
2001	300,000	60,000	0	360,000	Estimate
2002	130,000	13,000	0	143,000	Estimate
	$1,871,447	$794,774	$0	$2,666,221	

Customers have saved $1.87 million during the period based on the filing position the Company has taken.

It is important to note that the Company's CCT returns were audited by the BC Ministry of Finance and Corporate Relations for the years 1992 and 1993; the audit was completed in September 1998. The Minister did not dispute the Company's treatment of CIAOC for those years, therefore the Company had every reason to believe that its filing position with respect to the CIAOC was reasonable as well as acceptable to the Minister.

The filing position of Terasen Gas is consistent with the filing position of other gas utilities in the province including Terasen Gas Vancouver Island and PNG and in light of the assessments made by the Minister noted above, the Company feels it is appropriate and is vigorously challenging the re-assessments for the years 1995 and 1996. The Ministry has not assessed any penalties on the re-assessed years.

Should the Company not be successful, interest will be assessed but the actual tax liability will be no greater than if Terasen Gas had filed in that manner historically. On that basis, the only difference is the time value of money and therefore customers should be indifferent. So the savings of $380,000 are effectively net savings for customers.

51. Workshop Presentation of Scott Thompson

51.1 *Slide 6 of the presentation indicates that Terasen (Vancouver Island) decision provided for deferral account treatment on Pension Insurance costs. Please define what pension costs Terasen believes should be captured by a deferral account pursuant to this application*.

Response

As provided in the February 2003 Decision, pension costs to be included under deferral account treatment do not include costs for pensionable bonuses for executives. These costs continue to be covered by the shareholder. Variances of actual future pension expenses from the formula adjusted pension forecast will be captured in the deferral account in the same way they are in the Terasen Gas (Vancouver Island) settlement.

Total pension costs included in customer rates in 2003 are $5.543 million.

51.2 *Slides 8, 9, 10 and 11 indicate that the majority of cost of service items are going to be updated or forecast at annual reviews. Given the reduction of regulatory risk in terms of the probability of costs being disallowed at annual rate of return proceedings is it not fair to say that the risk profile of Terasen has been significantly reduced by approval of a long term PBR application*?

Response

The items subject to deferral and/or flow-through in the PBR are very similar to those embedded in the previous PBR. The Company is taking more risk in the area of capital spending in this Application. The risk profile of Terasen Gas will not been reduced by the approval of a long-term PBR of the form sought in the Application.

Please also see the response to Question 28.2 above.

52. Workshop Presentation of Randy Jesperson

52.1 *Slide 9 indicates that due processes are under implementation to improve customer attachment. Please describe these processes*.

Response

The New Attachment process referred to is called "Order Fulfilment". This initiative is a process re-design that was undertaken in conjunction with the work management system ("WMS") technology replacement project for attaching new customers to the system through the installation of new mains and services. This re-design was applied to the entire business process from the point of initial customer contact through to the final installation of the meter. The goal of this project was to create a significantly more customer friendly process. Included within the scope of the Order Fulfilment initiative was the replacement of the existing obsolete WMS with technology that enables the re-designed Mains and Services Order Fulfilment process in addition to most of the Utility's Operating and Maintenance processes and pipe related capital processes.

52.2 *At slide 14 it is indicates that the Inc./Utility separation study in underway. When will this study be completed? Will there be stakeholder input on the results of the study as to whether it complies with the Commission's direction? Please describe what stock option expenses and other cost of service items have been removed pursuant to the Commission's directions*.

Response

A plan for the separation of pensions, salaries and expenses as directed in the February Decision of February 4, 2003 will be filed with the Commission by the second quarter of 2003. The completed report outlining the details of the plan will be finalized in the summer and will be filed with the Commission by August 31, 2003. The actions will be implemented on or before January 1, 2004.

As per the Commission's direction, the stock option expenses have not been included in the cost of service. The Company has also complied with the removal of certain other cost items as directed by the Commission. These are noted in Section E of the Application.

52.3 *Slide 22 indicates that Terasen has no intent to compete down stream of the meter. It remains a concern to participates in industry down stream of the meter that there will be cross subsidy and/or support of non-regulated businesses which choose to compete down stream of the meter. How does Terasen intend to alleviate these concerns*.

Response

As discussed in response to Question 46, PBR puts in place incentives that align the interests of the Company and market participants to ensure there is no cross subsidization of non-regulated businesses. In addition, Terasen Gas will continue to be regulated by the BCUC and required to adhere to the Transfer Pricing Policy and Code of Conduct. The Annual Review process provides for the disclosure of all charges by the utility to non-regulated businesses. Any concerns market participants have regarding the charges to non-regulated businesses by the utility can be addressed through the Annual Review process, directly with the Company or with the BCUC throughout the term of the PBR.

52.4 *Slide 22 also indicates a focus on generating new load. However, little detail was provided as to how this is to be achieved. Please provide some description of these new load generating initiatives*.

Response

Please see the response to Question 29.

53. Workshop Presentation of John Reid, Slide 9

Mr. Reid indicated that the 2004 to 2008 PBR proposal "will improve regulatory oversights/efficiency". While the efficiency aspect of the proposal is understood in terms of lessening the regulatory load, it is not understood how regulatory oversight will be improved. Please clarify.

Response

The Company believes regulatory oversight will be improved because the PBR proposal provides for extensive continuing process on an annual basis (Annual Reviews), on an as needed basis (Approvals of CPCNs), and at certain defined check points (Mid-term Review).

The improvements in regulatory oversight flow in part from: (1) these increased continuing processes; (2) the adoption of a regulatory model that aligns customers and shareholders interests (instead of creating win/lose environments); (3) imposing a term that lets the regulator focus its oversight on long tern efficiencies and load building rather than be limited to shorter term solutions; and (4) on the inclusion of SQIs in the PBR Plan that would not be present in annual revenue requirement proceedings.

54. 2003 Revenue Requirements and Multi-Year Performance Based Ratemaking – Response to BCUC Staff Information Request No. 2

54.1 *In its response to BCUC request 20.10, the Company stated that "BC Gas is considering a number of approaches for the future use of this property [Lochburn] and will be reviewing proposals that not only involve the outright sale of the land but also the possibility of a long term lease with a developer." Please discuss possible plans for this facility. Please confirm that any funds acquired regarding the sale or lease of Lochburn, or any other Terasen property, will flow directly to the customer and will not be included in the "savings" attributed to increased efficiency or restructuring under the proposed PBR*.

Response

Proceeds from the sale of assets in the ordinary course of business would not flow directly to customers but rather would be treated as a credit to be applied to the reduction of rate base. As the net gas-plant-in-service component of rates is set by formula during the PBR period, proceeds from the sale would not directly affect customers' rates during the PBR period. Similarly, an acquisition of assets would not directly affect customers' rates during the PBR period.

The acquisition or sale of assets would have an indirect affect on customers through the proposed sharing mechanism. The proceeds from the sale of assets in the ordinary course of business would reduce rate base and would have an effect on the Company's ROE, which would benefit customers through the sharing mechanism.

Funds from the lease of assets would be considered as revenue (or an offset to costs) of Terasen Gas, but are not the type of revenue that would be re-forecast each year for the Annual Review, and accordingly any new lease revenue would not directly affect customers' rates. Similarly, a new lease of assets during the PBR Plan period, and any corresponding new lease costs, would not directly affect customers' rates. New lease revenue, and new lease costs, would affect the Company's earnings and therefore would be taken into account in the sharing mechanism.

Section 52 of the *Utilities Commission Act* requires that, except in the ordinary course of business, a public utility must not dispose of its property without first obtaining approval of the Commission. The Coastal Facilities CPCN Order approved the sale of surplus land at Lochburn provided the net proceeds are used for the benefit of utility ratepayers. That Order obligates Terasen Gas to seek approval from the Commission for any proposal that would depart from the customers receiving the benefit.

54.2 *In Appendix 3 to the BCUC Staff Information Request 29.18.4, CIBC World Markets (August 1, 2002) noted that there was a "potential for upwards revisions for our earnings estimates if merger synergies are partially retained through a new performance based regulation (PBR) framework." Please provide details regarding the "merger synergies" referred to in this report*.

Response

The merger synergies would relate to things such as the gas control and SCADA contracts the Company has entered into with Terasen Gas Vancouver Island and operational integration initiatives etc. The degree to which incremental synergies may be obtained beyond those already achieved or contemplated in the Commission's February 2003 Decision is not known at this time.

54.3 *In Appendix 3 to the BCUC Staff Information Request 29.18.4, CIBC World Markets (August 1, 2002) also noted that there was a "potential for BC Gas to participate in electricity restructuring." Please explain how such participation could affect the PBR and customer rates*.

Response

Although it is anticipated that direct participation in any provincial electricity restructuring would not be undertaken by Terasen Gas but rather through Terasen Inc. or other affiliates, to the extent that operational integration, facilities rationalization, etc. to be undertaken in overlapping service territories of the gas and electric operations there may be opportunities to reduce costs in Terasen Gas. Such cost savings would be captured under the sharing mechanism.

54.4 *In Appendix 3 to the BCUC Staff Information Request 29.18.4, RBC Capital Markets (August 1, 2002) noted that "Should BC Gas receive a negative decision from the BC Utilities Commission regarding its performance based regulatory proposal … the company's earnings may fail to reach our target, having negative share price implications." Please provide details with regards to value of earnings RBC Capital has attributed to a PBR as understood by Terasen*.

Response

It is apparent from the analyst's report that they ascribe some incremental value to the Company under a PBR regime as it creates opportunities to generate additional benefits that will accrue to customers through sharing and to the shareholder through incremental earnings. The Company does not know what value of earnings that RBC Capital has attributed to a PBR.

55. Letter No. L-48-02

BC Gas requested approval to recover $5.6 million in "development and marketing expenditures from BC Gas customers in the event the IPC project does not proceed." At what point does Terasen make the determination that the project will not proceed?

Response

Terasen Gas believes that the Inland Pacific Connector project will be required to meet the needs of natural gas consumers in the region within the term of the applied for PBR. A determination of whether or not the project will ultimately proceed will be based on an assessment of regional supply, demand, shipper commitments and the status of other infrastructure projects serving the region.

56. General Question

56.1 *Please provide a copy of the DSM report for 2002 "DSM Great Energy Saving Event" where the Federal Government and equipment suppliers contributed funds and rebates for installing high efficiency equipment. This report was unavailable at the time of the revenue requirement hearing*.

Response

An independent evaluation of this DSM program is being conducted in conjunction with, and co-funded by, Natural Resources Canada. Participant and non-participant surveys are currently underway and the final report is expected to be complete by the fourth quarter of 2003.

56.2 *What was the dollar value of Terasen's greenhouse gas emission credits*?

Response

Terasen has not sold any GHG emission credits associated with its DSM programs, and no dollar value has been ascribed to these emission credits.

56.3 *It is understood that participating customers collectively reduced their emissions by 11,000 tonnes of CO2 equivalents and that these customers were required to sign over their emission credits to Terasen. Do these credits go to BC Gas Utility or BC Gas Inc*.?

Response

Customers choosing to participate in the DSM program completed a coupon. The coupon wording was as follows:

> "By taking part in this offer, your central heating system may use less gas and produce fewer emissions. You agree that BC Gas may record any resulting emission reductions you have along with those of other participating customers and credit them to our Greenhouse Gas Management Program."

The referenced Greenhouse Gas Management Program is a utility initiative and the credits were assigned to Terasen Gas as a condition of participating in and receiving cash rebates from the 2002 Demand Side Management Program. By aggregating the credits from participating customers, Terasen was able to calculate the secondary benefit of appliance emission reductions from DSM participants. At the present time there is no tangible cost or benefit to any participating party.

56.4 *What is the forecast revenue from non-regulated business activities during the period of the proposed PBR*?

Response

If the question refers to revenues of non-regulated affiliates of Terasen Gas, the Company does not have these forecasts and they are not relevant to this proceeding.

If the question refers to non-regulated revenues within the Terasen Gas, the forecast is approximately $250,000 per year, mainly for magazine advertising revenues from third parties.

56.5 *What is the forecast cross charges between Terasen and non-regulated businesses of BC Gas during the PBR period*?

Response

Set out below is a table that summarizes the cross charges to non-regulated businesses included in the forecast.

	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Forecast 2008
Total cross charges	**$ 4,035,788**	**$ 4,152,235**	**$ 4,272,458**	**$ 4,396,573**	**$ 4,524,710**

56.6 *What is the anticipated activity of Terasen in business activities down stream of the meter during the PBR period*?

Response

The Company's activities downstream of the meter focus on safety related trouble calls. While Terasen Gas still performs a limited amount of safety related burner tip service at customer's request, it does not solicit this business and the Company does not anticipate performing any work incremental to the activities currently undertaken. The Company would like to work co-operatively with industry associations to develop load building initiatives but not to enter into competition with the industry.

56.7 *Please confirm that any system upgrades, or new facilities (i.e. LNG), relating to Vancouver Island Generation Project will not be to the account of the customers*.

Response

Terasen Gas confirms that any costs of facilities on the Terasen Gas Vancouver Island system will not be borne by the customers of Terasen Gas Inc. To the extent such facilities are constructed, the costs would be borne by customers in the territory served by Terasen Gas (Vancouver Island).

56.8 *Has Terasen considered outsourcing either its human resources or its engineering departments*?

Response

Yes. Outsourcing of some or even all processes in a support activity can deliver overall cost savings and/or provide access to specialist resources and expertise in a cost-effective manner. This is true in both Human Resources and Engineering. It is also true in many other areas of the Company.

The Company is continually reviewing and testing for efficiencies in all processes and does not exclude outsourcing as an option. The outsourcing of Terasen's whole customer care activity to CustomerWorks is indicative of Terasen Gas' open attitude to outsourcing when it makes sense.

With respect specifically to Human Resources, over the years a number of cost-benefit reviews have been conducted and the following processes have been outsourced:

- adjudication of short and long-term disability claims,
- pension estimates for the company's defined benefit plans, and
- employee and family assistance support (specialists for dealing with confidential personal, legal and financial employee issues).

In Engineering Terasen Gas has always used a combination of employees and outside consultants to provide Design Engineering, Engineering Consulting and Project Management Services to the Distribution and TransAM Groups. For the most part, day to day work is performed by employees and larger more complex and less frequent projects are tendered to outside contractors with the necessary skills. Certain very specialized work is performed by in-house employees because there are no qualified external service providers (e.g. Hydraulic System Analysis requiring extensive knowledge of the Terasen transmission and distribution system configuration). Terasen Gas' Engineering Services Group is continually analyzing its mix of in-house and contractor resources to ensure the optimal mix based on projected workloads, long range capital plans and system performance.

56.9 *Please provide a projected schedule which identifies cost changes to industrial customers over the course of the proposed PBR period*.

Response

The forecast annual delivery rate changes for the industrial customers over the course of the PBR period are those in Section H, Tab 1, Page 2 (in Line 6 of the table below the chart). These forecast rate changes represent a reasonable estimate of the rate changes under the PBR, however changes in items to be updated at the Annual Review such as interest rates, ROE or forecast revenues will affect the rates.

56.10 *Please provide a projected schedule which identifies changes to industrial customer service over the proposed PBR period. For of these questions, the industrial customers are defined as Rate Schedule 22, 22A, 25 and 27*.

Response

Terasen Gas, at this time, has not identified any particular changes to the industrial customer service as defined, over the proposed PBR period. However, changes could possibly arise as a result of any future rate design proceeding. In addition, any future substantive changes to upstream pipeline (e.g. Duke, TCPL) business rules, for example balancing provisions, may result in a need to modify rules for transportation service on Terasen Gas' system. Any potential changes would be subject to review and approval by the Commission.

56.11 *Does Terasen intend to file a rate design application during the proposed PBR period*?

Response

Rate design reviews are generally performed every five years. The last rate design review was held in 2001. Accordingly, it is likely that a rate design review would be undertaken during the term of the PBR.

56.12 *Does Terasen have any intention to change interruptible transportation schedules during the proposed PBR period*?

Response

Terasen Gas does not have any intention to change any rate schedules including the interruptible transportations schedules except as may be dictated by the results of any future rate design review as discussed in response to Question 56.11.

56.13 *Please describe how Terasen proposes to share in a revenue change such as the sale of land or another asset owned by the Utility during the course of the PBR term*.

Response

Please see the response to Question 54.1 above.

56.14 *Please describe how Terasen arrived at a proposed 50%/50% sharing of any efficiencies achieved by Terasen during the course of the PBR term*.

Response

Various options for sharing are available including asymmetric sharing, no sharing, dead-bands and collars. The Company's DRSM proposal included a dead-band and a collar on sharing whereas the PBR model that was in place for 1998 – 2001 featured 50:50 sharing of efficiency gains.

The stakeholder discussion leading to the development of the PBR is discussed in Tab B of the Application and in response to LMLGUA et al Question 8.2. As discussed at the Workshop, one of the design principles for the current PBR was to enhance the 1998 - 2001 model where appropriate. In addition, Terasen Gas sought to ensure that the model would be simple to understand and implement.

Sharing mechanisms reflect a trade-off between encouraging efficiency gains and perceived fairness and risk sharing. Sharing reduces the payback to the Company for investments in efficiency measures and thereby doubles the length of time necessary to recover restructuring costs or other efficiency investments. However from a fairness and risk sharing perspective, sharing provides an opportunity for customers to share equally in any gains achieved throughout the term of the PBR beyond those embedded in the adjustment factor. Furthermore, 50:50 sharing reduces the risk to both parties of extreme and unintended outcomes - either positive or negative. In the circumstances the 50:50 sharing proposal is appropriate.

Terasen believes that the proposed sharing mechanism is responsive to customer interests and is appropriate in the context of the proposed PBR.

56.15 *What is the after-tax monetized value of a 100 basis point increase in the Utility's ROE*?

Response

The after-tax monetized value of a 100 basis point increase in the Utility's ROE is an increase of $7.6 million. The equivalent revenue requirement impact of a 100 basis point increase in ROE is an increase of $11.6 million.

56.16 *What is the monetized value of a .75% productivity factor improvement for the year 2003*?

Response

The monetized value of a 0.75% adjustment factor improvement for the year 2004 is a reduction in the revenue requirement of approximately $2 million. In the fifth year of the proposed PBR Plan the impact of the 0.75% adjustment factor grows to approximately $16.2 million.

56.17 *Under the proposed PBR period, what percentage of the operating and maintenance costs of Terasen is Terasen at risk during the PBR period. For clarity, what percentage of the total operating and maintenance costs of Terasen are not subject to deferral accounts or annual adjustments in the PBR period*.

Response

During the PBR period, pension costs and insurance costs are subject to deferral accounts. These two items represent about 5% of gross O&M expenses, so the percentage of total operating and maintenance costs that are not subject to deferral account or annual adjustments in the PBR period is approximately 95%.

56.18 *Has there been an impact on Terasen as a result of the significant improvement on the value of the Canadian dollar in recent months? Has the benefit or detriment been to the customer account or to the shareholder account*?

Response

Terasen Gas does not have any material foreign exchange exposure which would result in significant costs or benefits to customers or shareholders. However, the recent appreciation of the Canadian dollar relative to the U.S. dollar benefits the customers of Terasen Gas indirectly to the extent that the natural gas commodity prices are referenced to U.S. markets and are priced in terms of U.S. dollars.

Most of Terasen Gas' natural gas commodity supply is priced in Canadian dollars and sourced from Alberta (AECO) and Northern B.C. (Station No. 2). These Canadian pricing locations are closely referenced via a basis differential to the U.S. NYMEX exchange. With the improvement in the exchange rate and no offsetting change in the basis differential, the AECO and Station No. 2 prices have then reduced, in comparison to the NYMEX prices proportional to the change in the exchange rate. In addition, a smaller portion of Terasen Gas' gas is sourced and priced at Sumas in U.S. dollars. Customers would benefit from the Canadian dollar appreciation if there is no change in the basis differential at Sumas.

It is also expected that should the recent appreciation in the exchange rate persist that some materials costs and the costs of Company use fuel may be lower in future. The benefits of such lower costs would be shared with customers through the sharing mechanism.

56.20 *Please list all outstanding tax related assessment or disputes which Terasen is involved in, the amounts of those matters in dispute and the present status of the dispute. Also, indicate what costs have been incurred by Terasen in pursuing those disputes*.

Response

The Company's federal tax returns are audited annually by the Canada Customs and Revenue Agency ("CCRA"). The CCRA is currently auditing the 1999 year. Currently there are no matters in dispute.

The Company's provincial tax returns are audited by the BC Ministry of Revenue. The CCT audit and disputes have been discussed elsewhere. The Ministry is also currently conducting an audit of Social Service Tax for the years 1997 to the present.

56.21 *Please provide the average customer use per account from January 1, 2003 to April 30, 2003, corrected for degree day, and compare those to the use per account for the same period for 2002 and 2001*.

Response

The table below compares usage by month for the requested years. The results for 2003 are still preliminary. The 2003 unadjusted use rate (actuals) for the period January to April 2003 for Rate 1 is 46.9 GJ. The corresponding degree day variance for the same period is 6% warmer than normal. Due to the nature of accounting for accruals, the monthly use rates should be considered preliminary and may change due to various adjustments and cycle billing issues affecting customer count. The adjustments for any given month are usually not fully incorporated until a few months after.

2001					
	Jan	**Feb**	**Mar**	**Apr**	**Jan-Apr**
RS 1	16.1	12.2	11.3	7.8	47.4
RS 2	47.9	38.4	35.5	23.7	145.5
RS 3/23	486.4	379.3	388.2	277.8	1,531.7

2002					
	Jan	**Feb**	**Mar**	**Apr**	**Jan-Apr**
RS 1	16.6	13.4	11.5	8.2	49.7
RS 2	49.6	39.9	34.6	22.9	147.0
RS 3/23	493.1	436.7	406.2	314.7	1,650.7

2003 (Actual)					
	Jan	**Feb**	**Mar**	**Apr**	**Jan-Apr**
RS 1	13.3	13.4	11.4	8.8	46.9
RS 2	37.1	42.9	35.3	23.1	138.4
RS 3/23	410.3	432.5	400.8	290.0	1,533.6

56.22 *What has been the total energy transported to customers for the period January 1, 2003 to April 30, 2003 and for the same period for 2002 and 2001*?

Response

The table below compares normalized energy in terajoules by month for selected years. As discussed in the response to Question 56.21 above the results for 2003 are still preliminary and are unadjusted (actuals).

2001	**Jan**	**Feb**	**Mar**	**Apr**	**Jan-Apr**
RS 1	10,910.7	8,274.6	7,661.9	5,314.3	32,161.5
RS 2	3,470.1	2,779.8	2,573.1	1,716.5	10,539.5
RS 3/23	3,012.5	2,354.9	2,407.9	1,715.3	9,490.6

2002	**Jan**	**Feb**	**Mar**	**Apr**	**Jan-Apr**
RS 1	11,334.2	9,154.8	7,864.3	5,622.3	33,975.6
RS 2	3,607.6	2,909.9	2,525.6	1,671.0	10,714.1
RS 3/23	3,160.4	2,717.5	2,542.8	1,977.1	10,397.8

2003 (Actual)	**Jan**	**Feb**	**Mar**	**Apr**	**Jan-Apr**
RS 1	9,202.0	9,221.6	7,881.7	6,104.9	32,410.2
RS 2	2,705.5	3,124.7	2,565.1	1,677.4	10,072.7
RS 3/23	2,555.2	2,691.2	2,493.4	1,802.3	9,542.1

56.23 *Should the Canadian economy experience deflation, is Terasen still prepared to measure controllable expenses based on CPI less .75%*?

Response

The Company would accept the results of the formula in a deflationary environment subject to triggering the Off-Ramp provisions of the PBR. Terasen is conscious of the potential risk of deflation, given the current low inflation rate environment and the low rates of inflation (and deflation) and economic growth being experienced in the United States and other countries throughout the world. However, given the current CPI outlook for BC, Terasen believes that a formula linking CPI less 0.75% is reasonable and is prepared to accept the risk that actual inflation may be lower than currently projected.

The response to BCUC Staff Question 3.5 provides a discussion of potential modifications to the formula that could be made to limit the impact of large variances from the anticipated CPI.

APPENDIX A

RESPONSE TO LOWER MAINLAND LARGE GAS USERS ASSOCIATION ET AL INFORMATION REQUEST No. 1, QUESTION #1.1

BC Gas Inc.
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Canada V6E 4M4

Tel 604-443-6500
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March 18, 2003

British Columbia Utilities Commission
6th Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. R.J. Pellatt
Commission Secretary

Dear Sirs:

Re: BC Gas Utility Ltd.
GCRA and RSAM Recovery, Net of Tax

On February 11th, 2003, BC Gas representatives met with Commission staff to review and discuss the Utility's recording and recovery plans for the GCRA and RSAM deferral accounts in light of recent Federal and Provincial corporate income tax rate reductions. As discussed at the meeting, this letter lays out the situation with respect to the accumulation in the accounts, the Company's tax loss utilization plan and actions, the monetary effects of the Utility's tax losses in light of tax rate reductions, and our proposed resolution to the attribution of related tax losses as between BC Gas Inc. and the Utility customer.

To summarize the situation, in late 2000 and throughout 2001 rapid and unanticipated increases in gas commodity prices resulted in BC Gas Utility recording unprecedented levels of GCRA and RSAM deferrals. The Utility followed the usual, approved practice of recording these deferrals on a net-of-tax basis, by which the deferral accounts are reduced by the amounts of expected future tax savings. During the same period the Utility was involved in a process of tax loss planning (as discussed below) that had been reviewed and acknowledged by the Commission. As a result of the high gas cost deferrals and the tax loss plans the Utility had excessive tax deductions, leading to tax loss carry forwards. The situation then became problematic when the Federal and Provincial corporate tax rates decreased causing the loss carry forwards to decrease in value. The unintentional effect of the non-Utility tax loss utilization plan in concert with unanticipated higher gas costs and tax rate reductions have conspired to diminish the current value of tax losses. BC Gas believes that a fair resolution to the matter can be reached. This letter proposes a resolution that balances the effect on customers and shareholders of the unintentional and unexpected result of gas cost increases, tax loss utilization plans and the decrease in tax rates.

Prior to proposing a resolution to the allocation of the effects of the tax rate reductions between the deferral accounts in the Utility and BC Gas Inc., some additional background information relating to the circumstances of the GCRA and RSAM accumulations, the company's tax mitigation initiatives, and quantification of the monetary impacts is warranted.

GCRA Accumulation

The circumstances faced in 2000 and 2001 by BC Gas Utility and other west coast local distribution companies ("LDCs") are well known. Natural gas prices reached peak levels continent-wide in late 2000 and early 2001. The west coast LDCs experienced major repercussions from the failed regulatory reform of electricity markets in California and suffered the effects of price spikes that were more extreme than in the rest of the continent. Deferral accounts for uncollected commodity and fuel costs reached into the ten of billions of dollars and some companies were put into extremely precarious financial positions.

For BC Gas Utility and its customers these circumstances resulted in unprecedented rate increases in 2000 and 2001. In spite of the large rate increases, the Utility's GCRA more than tripled in the year 2000, opening the year at $42 million and closing at $143 million. The account increased by $99 million in the month of December, 2000 alone. The balance continued to grow in 2001, reaching $225 million in January and remaining above $175 million in every month up to October. The balance moderated somewhat in the final quarter of 2001, dropping to $138 million by year-end. The net additions to the GCRA in 2001 totaled $62 million, so that even though $67 million was collected from customers in 2001, the balance decreased by only $5 million. The attached Schedule 1 ("GCRA/RSAM Tax Analysis") shows the GCRA balances for the period 2000 through 2003.

The Company's large GCRA build-up during 2000 and 2001 were not immediately and fully passed on to customers. BCUC Order No. G-124-00 required the Company to amortize the ending 2000 GCRA balance over three years. In early 2001, the GCRA/Gas Cost Flow-through Guidelines (BCUC Letter No. L-5-01) reaffirmed the three-year amortization of the 2000 balance but established a one-year amortization period for balances accruing after December 31, 2000. Because of the unprecedented nature of the gas cost increases it was anticipated at the time that the increases were unsustainable and that the build up in the GCRA would be manageable. Had the GCRA increases been less severe and more manageable, the recovery of gas supply costs in rates could have been better matched to the costs as incurred, resulting in lower growth of the GCRA during the period. Therefore, the effect on the existing tax situation would have been less severe. That said, the Company understands and supports the decisions that were made to help customers manage through the unprecedented commodity cost run-up.

RSAM Accumulation

As a further consequence of the abnormally high commodity costs, the Company also experienced substantial increases to the RSAM account. The RSAM accumulation was delayed somewhat relative to the GCRA because customer reaction in terms of reduced gas usage began only after commodity increases were flowed through to customers in 2001. As shown on Schedule 1, additions to the RSAM account were $30 million in 2001. The current practice is to amortize RSAM balances over three years.

Tax Mitigation Plans

Combined Federal/Provincial corporate tax rates have decreased from 44.5% in 2000, to 43.5% in 2001, 38.5% in 2002, and 36.5% in 2003. In advance of these tax rate changes the Company met with Commission staff on June 23, 1998, and presented a plan whereby tax losses from other BC Gas Inc. companies, which would otherwise go unutilized, would effectively be used as deductions against Utility income. In a follow-up letter to the Commission dated September 21, 1998, the plan was further explained. By letter of December 10, 1998, the Commission accepted the plan and BC Gas Inc. commenced the process to use and deduct certain tax losses against Utility earnings in 1999 and 2000.

BC Gas Inc. initiated the Tax Loss Utilization Plan (TLUP) measures to minimize its overall level of income taxes payable. The TLUP effectively transfers losses from entities without taxable income to others that have taxable income. BC Gas Utility entered into TLUP transactions which created tax deductions of $49 million in 1999 and $53 million in 2000. The large GCRA accumulation in late 2000 generated a tax deduction that, when combined with the TLUP deductions, resulted in total available deductions in excess of taxable income in 2000. As a result, the Company did not execute the planned TLUP arrangement for 2001 that was internally developed and approved in late 2000. Of the TLUP deductions taken in 1999 and 2000, $9 million of the 1999 TLUP program and $45 million of the 2000 TLUP program would have been lost had they not been deducted in the 2000 tax return. The remaining losses were not close to expiring.

Analysis of Tax Savings

The attached Schedules show:

1. an analysis of the tax savings on GCRA/RSAM recoveries and the lost tax savings; and,

2. summarized Utility tax returns for 1998 to 2002.

The tax savings arose because income tax rates were higher when the GCRA was built up than when the GCRA balances were recovered from customers. The first Schedule sets out the potential total tax savings estimated at approximately $9.7 million, due to the recovery of the GCRA at tax rates lower than those in effect when the GCRA accumulated. A similar analysis for the RSAM account yields tax savings over the period of $3.6 million, which is calculated using the assumption that the balance of the outstanding RSAM will be recovered in 2003. If account recoveries are delayed longer (which appears likely given recent commodity increases), the amounts would be higher since an additional tax rate reduction of 2% is anticipated in 2004. In total, assuming full account balance recoveries in 2003, the potential GCRA and RSAM tax savings on recoveries are estimated at $13.3 million.

Before the rapid, unanticipated increase in the GCRA in late 2000, the tax plans for the year 2000 had already been in place for some time and, therefore, the deduction for the entire GCRA increase was not realized in the 2000 tax return. The Company ended up with a 2000 loss carry-forward of $95 million as well as unutilized Class 12 deductions of $21 million, as shown on the Schedule 2. Class 12 deductions are treated on a net-of-tax basis similar to the GCRA and RSAM deferrals.

In 2001 further GCRA additions, the extended recovery period, and the additions to the RSAM account discussed earlier were contributing factors in minimizing taxable income once again. In 2001 the Company was able to deduct only $7 million of the prior year's loss carry-forwards and it could not utilize the 2000 Class 12 deductions or the 2001 Class 12 deductions of $26 million. The remaining losses and Class 12 pools are expected to be deducted in 2002 and 2003 when income tax rates are significantly lower than in 2000 and 2001. The effect of the lost tax savings due to the delayed deductibility of the loss carry forwards is $8.5 million as shown on the first schedule.

As summarized on Schedule 1, if the Company is able to deduct the remainder of its losses and Class 12 pools as planned in 2002 and 2003, the net customer benefit to be realized from declining tax rates is estimated at $4.8 million.

2002 Application Withdrawal

An additional factor to consider with respect to income taxes arises from the Company's withdrawal of its 2002 Revenue Requirement Application. Item 5 in the Reasons for Decision (see Page 5 of 5) attached to BCUC Order No. G-123-01, which approved the withdrawal of the 2002 Revenue Requirements Application, indicated that in 2002 there would be no rate changes or deferral accounts related to income taxes, property taxes and capital taxes. Although reductions in future income tax rates were expected at the time, the Commission agreed to this tax treatment largely because the Company was not seeking increases due to rate base additions for regular capital and Certificates of Public Convenience and Necessity. The Company was also required to absorb cost increases in other areas such as operating and maintenance costs and property taxes, which were expected to rise during the year. The Company accepted that it could manage the withdrawal of its requested 2002 increase on the basis that it would retain the income tax savings resulting from the lower tax rates.

Conclusion

It is evident that from 2000 to 2003, under normal conditions, the Company had the potential to realize $13.3 million in tax savings for the customer by deferring a substantial level of costs and then subsequently recovering the costs over a period of declining tax rates. However, due to the unforeseen and unintentional circumstances of 2000 and 2001, only $4.8 million of the tax savings will be realized.

The Company believes that it acted prudently and with the knowledge of the Commission in seeking to minimize its income taxes with the TLUP and that, in view of the unusual and extreme circumstances, a degree of judgment should be applied to determine a fair resolution. In the Company's view, to recognize the full, unrealized effect of the tax savings for the customer would, at this stage, be punitive and unfair to the shareholder given the intent of its actions in 1999 and 2000 – actions that, in hindsight, only proved to be detrimental when subsequent gas costs rose, GCRA balances accumulated and income tax rates dropped.

The Company recommends that, in view of the foregoing, it would not be appropriate to reflect the full (unrealized) tax savings of $13.3 in customers' rates as only $4.8 million will actually be realized and the remaining $8.5 million would be to the immediate account of the shareholder.

While BC Gas believes the actions of the Company have been such that no action need be taken in adjusting the recoverable GCRA balance for the full effect of the tax savings, we acknowledge that the TLUP was intended to have no adverse effect on Utility customers. The TLUP, combined with the gas cost run-up and the tax rate decrease have combined to leave less tax savings than if the TLUP had not been used. Accordingly, BC Gas proposes that a fair solution to the situation including recognition of the 2002 withdrawal year to which $4.9 million of savings are attributed, would be for an equal sharing of the remaining tax benefit of $8.5 million between the Utility customers and BC Gas Inc. An equal sharing recognizes that the actions of BC Gas management were in no way intended to deprive customers of appropriate tax savings, while acknowledging the combined effect of the TLUP, GCRA build up and declining tax rates on the deferral accounts. If agreeable, the Utility will adjust the net of tax deferral accounts to reflect a combined customer benefit of approximately $9.0 million ($4.8 million plus ½ of $8.5 million) and BC Gas Inc. will absorb $4.25 million of tax expense.

BC Gas recognizes the complexity and problematic nature of this situation but assures the Commission that in no way was the result intended or foreseen. In hindsight, we acknowledge that the matter should have been communicated to the Commission earlier, however as can be seen from the Schedules the ultimate value of the tax savings and the effects on the tax loss carry forwards is still being determined and with current gas cost increases it is uncertain whether the matter will be concluded in 2003.

BC Gas would be pleased to meet with Commission staff to discuss this issue further. If any additional information is required please contact Ian Anderson at 604-443-6552.

Yours truly,

BC Gas Inc.
Per:

Ian D. Anderson,
Vice President Finance and Corporate Controller

IDA/ib
Encl.

BC Gas Utility Ltd.
GCRA/RSAM Tax Analysis
($Millions)

March19, 2003
Schedule 1

	Applicable Tax Rate Reduction	Recovery Amount	2000	2001	2002	2003 est	Total
			Tax Savings (Losses)				
Tax Savings - GCRA Recoveries							
2000 closing balance recovered in 2001	1%	67		0.7			0.7
2000 closing balance recovered in 2002	6%	69			4.2		4.2
2000 closing balance recovered in 2003	8%	7				0.5	0.5
2001 additions recoverd in 2003	7%	62				4.3	4.3
2002 additions recovered in 2003	2%	0				0.0	0.0
Total GCRA Tax Savings		205		0.7	4.2	4.9	9.7
Tax Savings - RSAM Recoveries							
2000 closing balance recovered in 2001	1%	5		0.1			0.1
2000 closing balance recovered in 2002	6%	12			0.7		0.7
2000 closing balance recovered in 2003	8%	6				0.5	0.5
2001 additions recoverd in 2003	7%	30				2.1	2.1
2002 additions recovered in 2003	2%	14				0.3	0.3
Total RSAM Tax Savings		67		0.1	0.7	2.8	3.6
Total Tax Savings on GCRA/RSAM Recoveries		271	-	0.7	4.9	7.7	13.3
Lost Tax Rate Reduction Savings							
2000 LCF utilized in 2001	1%	(4)		(0.0)			(0.0)
2000 LCF utilized in 2002	6%	(70)			(4.2)		(4.2)
2000 LCF utilized in 2003	8%	(21)				(1.7)	(1.7)
2000 Class 12 utilized in 2002	6%	(21)			(1.3)		(1.3)
2001 Class 12 utilized in 2002	5%	(26)			(1.3)		(1.3)
Total LCF/Class 12 Lost Savings		(142)	-	(0.0)	(6.8)	(1.7)	(8.5)
Net savings (losses)		129	-	0.7	(1.9)	6.0	4.8
Tax Rates			44.5%	43.5%	38.5%	36.5%	

GCRA/RSAM Account Balances (Gross)

	2000	2001	2002	2003 est	Total
GCRA Account					
Opening	42	143	138	69	42
Additions	120	62	0		182
Recovery	(19)	(67)	(69)	(69)	(224)
Closing	143	138	69	-	-
RSAM Account					
Opening	17	23	47	49	17
Additions	9	30	14		52
Recovery	(3)	(5)	(12)	(49)	(69)
Closing	23	47	49	-	-

BC Gas Utility Ltd.
Tax Return Summary
($Millions)

March 17,2003

	1998	1999	2000	2001	2002
					Estimated
Regulated Utility Taxable Income (for tax expense)	104	125	107	106	103
Additions (Deductions) for Tax Purposes					
GCRA/RSAM	(71)	(32)	(107)	(19)	67
TLUP	-	(49)	(53)	-	(7)
Other	(58)	(58)	(42)	(80)	(91)
Total	(129)	(139)	(202)	(99)	(31)
Legal Entity Taxable Income (Loss)	(25)	(14)	(95)	7	72
Loss Carryforward/back	25	14	76	(7)	(72)
Net Loss Carryforward	-	-	(19)	-	-
Loss Carryforward Pool					
Opening		-	3	98	91
Additions	25	14	95		
Carried back	(25)	(11)			
Carried forward				(7)	(72)
Closing	-	3	98	91	19
Class 12 Not Claimed			21	26	
Class 12 Pools (cumulative)	-	-	21	47	

BRITISH COLUMBIA UTILITIES COMMISSION
Staff Information Request No. 1

BC Gas Utility Ltd. ("BC Gas", "BCGUL")
GCRA and RSAM Recovery, Net of Tax

1.0 Net of Tax Treatment
Reference: March 18, 2003 Application, BC Gas 1992 Revenue Requirements Decision, Commission Orders No. G-53-94 and G-123-01

Page 1 of the March 18, 2003 Application states that "The Utility followed the usual, approved practice of recording these deferrals on a net-of-tax basis, by which the deferral accounts are reduced by the amounts of expected future tax savings."

1.1 Please confirm that BC Gas has been recording the activity in the GCRA and RSAM deferral accounts consistent with the accounting treatments described on Section 3.8 of the BC Gas 1992 Revenue Requirements Decision and Commission Order No. G-53-94. If not, please explain.

1.2 Under the net of tax treatment, please confirm that BC Gas reduces the gross addition to the GCRA and RSAM deferral account for the current year by the tax saving at the prevailing tax rate for the current year. Please confirm that the deferred net of tax balance is not subsequently adjusted for changes in tax rates.

1.3 On Schedule 1, a gross GCRA addition of $120 million for the year 2000 and a tax rate of 44.5 percent is shown. Please confirm that by deferring these GCRA costs in 2000 the shareholder has deducted the $120 million on the BC Gas legal entity's tax return, provided utility customers with financing for the after-tax amount of approximately $67 million and is compensated by the allowed return on the deferred costs and the amortization to cost of service.

1.4 Please confirm that when BC Gas calculates a rate to recover the amortization of an after tax amount in the GCRA or RSAM deferral account that the rate is based on the gross up of the after tax deferred amount at the current income tax rate. Please confirm that the $13.3 million of tax savings on Schedule 1 of the GCRA/RSAM Tax Analysis represents the gross-up of the deferral account amortization at the current tax rate rather than the tax rate used in the net of tax deferred addition.

1.5 Commission Order No. G-123-01 approved the BC Gas request to withdraw its 2002 Revenue Requirements Application. Item (f) of the BC Gas November 1, 2001 withdrawal of its 2002 Revenue Requirements Application states "Rates will not be adjusted to take into account the effect of changes in property taxes, income tax rates and corporation capital tax and the effect of those changes will not be recorded in deferral accounts."

Please explain how the net of tax addition to the GCRA and RSAM deferral accounts and the rate charged to recover the deferral account amortization was impacted by the withdrawal of the 2002 Revenue Requirements Application.

2.0 Tax Loss Utilization Plan ("TLUP")
Reference: BC Gas Letters dated September 21, 1998 and November 27, 1998, Commission Letter dated December 10, 1998 and March 18, 2003 Application

2.1 In a September 21, 1998 letter, BC Gas briefly described the TLUP to the Commission that the BC Gas group of companies intended to put in place in late 1998 or early 1999 and that it was seeking an advance tax ruling.

2.1.1 Please provide a copy of the September 21, 1998 letter with attachments.

2.1.2 Prior to the TLUP implementation:

(a) what were the tax losses in the non-regulated businesses of the BC Gas corporate group ("Losscos") and when were these tax losses expected to expire?
(b) what was the projected taxable income (loss) by year from 1998 to 2002 for the utility legal entity and the Losscos separately?

2.1.3 The TLUP was described as creating deductible interest in BCGUL and taxable interest income in the Losscos. What did this new debt financing displace in the BCGUL's capital structure, did it displace short-term debt or equity or result in excess capitalization? What was the interest rate of this debt financing?

2.2 Under the TLUP did the BC Gas group of companies minimize discretionary tax deductions such as capital cost allowance in order to claim the tax loss carryforwards? What was the amount of discretionary tax deductions by year from 1998 to forecast 2002 for the BC Gas group of companies?

2.3 Has the BC Gas group of companies filed amended tax returns for 1998 to 2001? Are there any restrictions on filing amended tax returns for these years?

2.4 The 2000 GCRA gross additions of $120 million on Schedule 1 and the 2000 Regulated Utility Taxable Income of $107 million on the Tax Return Summary appear to be the activity for the BC Gas service areas of the Lower Mainland, Inland and Columbia and does not include activity of the Fort Nelson service area. Please confirm that the legal entity of Fort Nelson Gas Ltd. was excluded from the TLUP.

2.5 Please provide a copy of all records, notes, memoranda, briefing and background documents and all other correspondence and materials pertaining to the TLUP.

3.0 GCRA/RSAM Tax Analysis and Tax Return Summary
Reference: March 18, 2003 Application

3.1 In the section titled Tax Mitigation Plans on page 3, BC Gas states that the large GCRA accumulation in 2000 generated a tax deduction that, when combined with the TLUP deductions, resulted in total deductions in excess of taxable income in 2000.

Further to Question 2.2, the Tax Return Summary shows a 2000 Regulated Utility Taxable Income of $107 million and a Legal Entity Taxable Loss of $95 million. The 2000 Regulated Utility Taxable Income corresponds to Schedule III, page 40 of the BC Gas Annual Report to the Commission. The 2000 list of timing differences on Schedule III, page 42 of the Annual Report shows that capital cost allowance of $69 million was claimed.

Please explain if the BC Gas legal entity reduced the capital cost allowance deduction to zero for 2000 in an effort to minimize the legal entity's tax loss. If not, why not?

3.2 Please explain the deductions shown as "Other" on the Tax Return Summary from 1998 to 2002.

3.3 Further to Question 1.3, for the regulated utility on a stand alone basis, when the Regulated Utility Taxable Income by year from 1998 to 2002 from the Tax Summary Schedule is reduced by the corresponding GCRA/RSAM deductions a tax loss does not occur in any of those years. Since none of the loss carryforwards are caused by the net of tax treatment, why should the utility customers bear any burden for non-utility unutilized tax shields?

4.0 Benefits of TLUP

4.1 For each year from 1998 to 2002 please quantify the tax savings for the BC Gas group of companies that have resulted from the TLUP and identify the amount of the tax savings by year that was realized by the utility customers.

ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 2692

VIA FACSIMILE
(604) 443-6612

May 22, 2003

Mr. Ian Anderson
Vice President Finance & Corporate Controller
Terasen Inc.
1111 West Georgia Street
Vancouver, BC V6E 4M4

Dear Mr. Anderson:

Re: Terasen Gas Inc.
Application for Sharing Reduced Tax Savings
between Terasen Inc. and Terasen Gas Inc.

Further to your March 18, 2003 application to adjust the deferral accounts of Terasen Gas Inc. to share equally the reduced tax savings, we enclose Commission Order No. G-34-03 and Reasons for Decision.

Yours truly,

Robert J. Pellatt

cms
Enclosure
cc: Mr. Scott Thomson
Vice President, Finance and Regulatory Affairs
Terasen Gas Inc.
Fax: 604-592-7890

TGI/Cor/GCRA-RSAM Tax Loss Reasons

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-34-03

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Inc.
(formerly known as BC Gas Inc.)
for Approval of Sharing Reduced Tax Savings
between Terasen Inc. and Terasen Gas Inc.
(formerly known as BC Gas Utility Ltd.)

BEFORE:	P. Ostergaard, Chair	)	
	K.L. Hall, Commissioner	)	May 16, 2003
	R.H. Hobbs, Commissioner	)	

O R D E R

WHEREAS:

A. On September 21, 1998, Terasen Gas Inc. ("the Utility") informed the Commission of a tax loss utilization plan ("TLUP") that the Terasen group of companies planned to put in place in late 1998 or early 1999; and

B. The Utility had annual taxable income and several non-regulated businesses ("NRBs") had tax losses. The TLUP involved inter-company loans from the NRBs to the legal entity of the Utility to create deductible interest expense in the legal entity of the Utility and taxable interest income in the NRBs; and

C. All transactions in the TLUP were considered to be non-utility and were to have no adverse impact on the Utility nor its customers; and

D. On November 27, 1998, the Utility requested an acknowledgement letter from the Commission confirming that the TLUP had been reviewed and that no concerns had been raised; and

E. On December 10, 1998, the Commission issued the requested acknowledgement letter to the Utility; and

F. Income tax rates declined from 2000 to 2003 and on March 18, 2003, Terasen Inc. applied to the Commission for approval to adjust the deferral accounts of the Utility to share equally the reduced tax

BRITISH COLUMBIA UTILITIES COMMISSION	
ORDER NUMBER	G-34-03

savings that resulted from the effect of the non-utility TLUP in concert with unanticipated higher gas costs and tax rate reductions ("the Application"); and

G. The Application stated that deferring the recovery of higher gas costs, recording the additions to the Gas Cost Reconciliation Account and the Revenue Stabilization Adjustment Mechanism on a net-of-tax basis and the declining income tax rates from 2000 to 2003 provided utility customers with tax savings of $13.3 million and the Utility shareholders with tax savings of $4.8 million; and

H. The Application proposed that Utility customers and shareholders should share equally the difference in tax savings of $8.5 million. The proposed sharing would result in the Utility foregoing $4.25 million of the tax benefit by an adjustment to the Utility's deferral accounts. The shareholder would increase its tax saving by $4.25 million to $9.05 million; and

I. A Commission staff information request was issued on April 17, 2003 and responses were filed on May 6, 2003; and

J. The Commission has reviewed the Application and responses and considers that a determination is required.

NOW THEREFORE as set forth in the Reasons attached as Appendix A, the Commission finds that the Application is without merit and is denied.

DATED at the City of Vancouver, in the Province of British Columbia, this 22nd day of May 2003.

BY ORDER

Peter Ostergaard

Peter Ostergaard
Chair

Attachment

An Application by Terasen Inc.
(formerly known as BC Gas Inc.)
for Approval of Sharing Reduced Tax Savings
between Terasen Inc. and Terasen Gas Inc.
(formerly known as BC Gas Utility Ltd.)

REASONS FOR DECISION

The Terasen Inc. Application relates to the use of deferral accounts and the recovery of deferred expenditures in customers' rates. In order to smooth the rate impacts of certain volatile expenses such as the commodity cost of natural gas, the Commission approves the creation of deferral accounts, including the Gas Cost Reconciliation Account ("GCRA") and the Revenue Stabilization Adjustment Mechanism ("RSAM") account, which effectively remove the actual expenditures from the determination of customer rates. The Commission then approves the amortization of these expenditures over a number of years for recovery from customers. Since the expenditures are recognized as deductions for income tax purposes, the accounts are recorded on a net-of-tax basis. That is, the Utility reduces the gross additions to the deferral account for the current year by the tax saving at the prevailing income tax rate for the current year. This net-of-tax treatment keeps the shareholders whole and compensates them for the financing of the net of tax. Since the subsequent amortization is not recognized by the Canada Customs and Revenue Agency as a deductible expense, in order to keep the Utility whole, it is grossed up at the then-prevailing income tax rate. If the income tax rates decline from the time that a deferred cost is incurred to when it is amortized into rates, a smaller rate increase is required from customers in order for the Utility to pay income taxes at the current rate on the amortized amount.

As noted in the March 18, 2003 Application, the Utility followed the approved practice of recording the deferrals on a net-of-tax basis. The Application calculates that customers benefited by $13.3 million for the net-of-tax treatment of deferred expenditures and the decline in income tax rates from 2000 to 2003. However, during the same period the Utility initiated a Tax Loss Utilization Plan ("TLUP") to create greater tax-deductible expenses in the Utility in order to create income in related companies which otherwise would have had tax losses. Although the Utility did not believe that it required Commission approval for the TLUP, at the request of Commission staff, it wrote to the Commission on September 21, 1998 explaining that the plan is an acceptable method for transferring tax losses within a related corporate group. The letter explained that the transactions are excluded from the Regulated Utility tax expense calculation and that it would have "no adverse impact on the Regulated Utility nor its customers". At the Utility's request, in a December 10, 1998 letter, the Commission acknowledged that Commission staff had reviewed the TLUP transactions, and that no concerns have been raised.

On March 18, 2003, the Utility's parent company informed the Commission that as a result of high gas cost deferrals and the TLUP, the Utility had excessive tax deductions leading to tax loss carry forwards. Because Federal and Provincial corporate tax rates decreased during the period, the value of loss carry forwards decreased. The parent company then applied to the Commission for approval to adjust the Utility's deferral accounts to share the reduced tax savings. The Application stated that the net-of-tax deferral account treatment provided Utility customers with tax savings of $13.3 million but only a $4.8 million tax saving will be realized. This sharing would result in the customers foregoing $4.25 million of their tax savings.

After a review of the Application and subsequent information, the Commission determines that the net-of-tax deferral account mechanism operated properly for the benefit of the Utility and its customers, that the related group of companies had tax planning options other than TLUP, and that the TLUP did not provide any tax savings for Utility customers while the related group of companies received substautial tax savings.

The March 18, 2003 Application is denied.

APPENDIX B

RESPONSE TO LOWER MAINLAND LARGE GAS USERS ASSOCIATION ET AL INFORMATION REQUEST No. 1, QUESTION #40.2

BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, British Columbia
Canada V3S 2X7

Tel 604-576-7000
Fax 604-592-7890

April 24, 2003

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sirs:

Re: BC Gas Utility Ltd.
2002 Demand Side Management ("DSM") Status Report

Enclosed is the 2002 DSM Status Report identifying conservation and efficiency activities undertaken by BC Gas last year. As evident in the report the Company's 2002 residential program offers had high rates of customer and trades participation. The results stated in the report reflect customer rebates processed through February, 2003.

At Page 34 of the BCUC Decision regarding BC Gas' 2003 Revenue Requirements Application, BC Gas was directed to conclude its evaluations of existing DSM programs and file with the Commission in time for that information to be available to parties to a Commission proceeding for 2004 rates. The 2002 DSM Annual Report summarizes the findings of the 2001 program evaluations. Copies of the following consultant's evaluation reports are enclosed here:

> 2001 Residential DSM Campaign Evaluation, R.A. Malatest & Associates Ltd., November, 2002. Note: This report includes results from three residential DSM programs offered by BC Gas in 2001- the furnace tune-up, the heating system upgrade program, and the insulation/draft proofing program.
>
> BC Gas Commercial DSM Evaluation, R.A. Malatest and Associates Ltd., September, 2002. Note: This report pertains to the program identified as the Commercial Energy Utilization Advisory in 2001 and 2002.

BC Gas will be engaged this year in follow-up impact evaluation of its 2001 residential heating system tune-up and upgrade programs utilizing the additional year of customer billing data. The Company will also be conducting an evaluation of the 2002 residential heating system upgrade program in conjunction with its funding partner, Natural Resources Canada.

BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, British Columbia
Canada V3S 2X7

Tel 604-576-7000
Fax 604-592-7890

Any questions about this material or about the Company's ongoing DSM initiatives may be directed to Bruce Vernon at 604-592-7643.

Yours very truly,

BC Gas Utility Ltd.

Scott Thomson, Vice President
Finance and Regulatory Affairs

Attachment

cc: Registered Intervenors

April 24, 2003

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sirs:

Re: BC Gas Utility Ltd.
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Any questions about this material or about the Company's ongoing DSM initiatives may be directed to Bruce Vernon at 604-592-7643.

Yours very truly,

BC Gas Utility Ltd.

Scott Thomson, Vice President
Finance and Regulatory Affairs

Attachment

cc: Registered Intervenors

BC GAS UTILITY LTD.

2002

DEMAND SIDE MANAGEMENT (“DSM”)

STATUS REPORT

1.0 INTRODUCTION

As set out in the Consolidated Settlement Document with respect to BC Gas' 1998-2000 Revenue Requirements (extended to 2001 by BCUC Order No. G-48-00 and 2002 by BCUC Letter No. L-12-02), BC Gas is required to report on the status of its Demand Side Management ("DSM") programs to the British Columbia Utilities Commission ("Commission").

The current report is intended to provide an overview of BC Gas' DSM activities in 2002, with details pertaining to the progress of individual DSM programs against forecasted targets and objectives for the year. This report includes the results of residential sector incentive programs offered to November 30, 2002. Customer participation levels were higher than anticipated, resulting in processing of rebate claims through February 2003.

2.0 OVERVIEW OF DSM PROGRAMS AT BC GAS

BC Gas has continued to support and to promote Demand Side Management programs and initiatives during 2002. DSM efforts encourage the adoption of conservation and efficiency measures by customers to reduce or modify their end-use demand for natural gas. From the utility's perspective, customers who utilize gas prudently and efficiently are better positioned to cope with fluctuating energy costs. Such customers are also making a positive contribution toward the reduction of Greenhouse Gas emissions.

3.0 ONGOING INITIATIVES

As noted in the Company's 1999, 2000 and 2001 Annual Review DSM Status Reports, BC Gas has moved progressively toward targeted, shorter-term initiatives. One longer-term program offered in prior years, the commercial sector Efficient Boiler Program, was terminated in 2000, however a number of approved installations were not completed until late 2001 and finalization of customer incentive payments was not settled until early 2002. There were eight such installations for which incentives totalling $297,000 were paid in 2002 and none remain currently outstanding. A third-party process and impact evaluation of this program is being undertaken in 2003.

One broad-based incentive program launched in the mid-1990's, the commercial sector Firm to Interruptible Service Conversion program, (which provides financial assistance toward the installation of a back-up fuel system for firm service commercial or institutional Rate 3/23 or 5/25 customers who wish to move to the interruptible Rate 7/27) remained available during 2002 but no applications were received.

Destination Conservation ("DC"), a Kindergarten to Grade 12 school program involving both students and school facilities management staff, received funding from BC Gas in prior years and has been reorganized following financial difficulties in British Columbia. The program is now being run directly by DC Alberta with a co-ordinator located in Vancouver, and has been re-introduced to school districts in BC (for example, West Vancouver). Although no financial sponsorship for additional school districts was provided by BC Gas in 2002, BC Gas would like to continue its association and financial support for DC if additional school districts enter into agreements.

BC Gas DSM personnel were active in a number of community-based initiatives during 2002 including the Community Energy Association (previously known as the Energy Aware Committee) and collaborated with provincial and federal groups to review energy standards. The Company also co-sponsored a series of workshops with the federal government and the Canadian Gas Association (entitled 'Energy Matters') which brought subject matter experts to a number of interior communities for discussions on a broad range of energy conservation topics.

The company also provides print and web-based resources to customers including various publications such as the 'Hot Tips' booklet that continues to be requested by customers.

4.0 SHORT TERM INITIATIVES

Residential Heating System Tune-up

First offered by BC Gas in the summer of 2001 as a furnace tune-up, the heating system tune-up was re-launched in mid 2002 to include both furnaces and boilers. Customer reaction was very positive in 2001, with some 27,324 participants, and research conducted late in 2001 suggested strong continuing consumer interest in this type of rebate offer. Similar to the 2001 program the 2002 tune-up offer was formulated to encourage customers to engage a contractor registered with the provincial Gas Safety Program to perform a series of furnace or boiler maintenance operations, performance checks and appliance adjustments. The offer included a $25 utility bill credit for participants. The cost of the service prior to application of the bill credit averaged $88.00.

Results from the 2001 program suggest free-ridership in the program (i.e. the percentage of customers who would have performed the tune-up in the absence of the program) at 28% and, conversely, the proportion of customer participants who took other conservation and efficiency measures as a result of the tune-up visit, for example, weatherproofing or the installation of automatic setback thermostats, was found to be 25%.

Participation levels in the 2002 tune-up program significantly exceeded expectations (the target was 20,000 customer participants) with approximately 45,000 customers receiving a tune-up under the program, net of those that did not qualify (for example, customers who did not utilize a contractor registered with the provincial Gas Safety Program were not eligible to receive the incentive), a 65% increase over the previous year. More than 60% of all registered gas contractors in the service territory performed tune-ups in the 2002 program – there were 840 participating contractors out of an average total of 1300 contractors registered with the provincial Gas Safety Program.

The 2001 furnace tune-up program was evaluated by Malatest and Associates, an independent program evaluation consultant. Malatest indicated high levels of customer satisfaction (96% of customers found it easy or very easy to participate in the program; 90% were satisfied or very satisfied with the program overall). Malatest also indicated high levels of contractor satisfaction with the 2001 program (82% of contractors found it easy or very easy to participate; 74% were satisfied or very satisfied, 24% were neutral and none were dissatisfied).

The program design for 2001 and 2002 estimated the average annual natural gas savings at 3 GJ per participant. The Malatest evaluation of 2001 results attempted to perform a preliminary energy savings impact analysis based on participant billing records; however, Malatest advised they were unable to confirm the savings estimates due to insufficient data. The analysis technique being employed attempts to identify very small variations in natural gas consumption, in this case often less than 3%, and therefore requires a number of (weather-normalized) bill readings with which to compare to readings from prior periods. Since very few billing readings post tune-up were available for this analysis (a majority of the tune-ups were completed only after the onset of the 2001/2002 heating season), the consultant has recommended that the billing analysis portion of the 2001 program evaluation be attempted again over a longer period of time to provide more data points. BC Gas plans to pursue this analysis in the second half of 2003, but remains uncertain of the ability of the analysis to identify the finite savings levels anticipated.

Evaluation report pertaining to this program: 2001 Residential DSM Campaign Evaluation, R.A. Malatest & Associates Ltd., November 2002. Note: This report includes results from three residential DSM programs offered by BC Gas in 2001- the furnace tune-up, the heating system upgrade program, and the insulation/draft proofing program.

Residential Heating System Upgrade

Similar to a program offered by BC Gas in the fall of 2001, the 2002 Residential Heating System Upgrade program offered a $150 utility bill credit toward the purchase and installation of a replacement high efficiency (AFUE 90% or higher) furnace or boiler. An additional $150 utility bill credit (for a combined total of $300 per customer participant) was provided by Natural Resources Canada under a contribution agreement entered into between NRCan and BC Gas in mid-2002. This agreement provided for up to 3,000 rebates ($450,000) as well as a contribution of $130,000 toward the program's promotional costs.

An additional incentive ranging from $150 to $1000 in value toward the purchase of 22 different brands of residential high efficiency furnaces and boilers offered by 14 different suppliers was organized and promoted by BC Gas as part of this program. Virtually all BC suppliers of condensing high efficiency residential heating systems were represented. A supplier meeting held in February 2003 to discuss the program indicated universal support for the initiative from those attending.

The response rate for the 2002 upgrade offer was significantly higher than projected with 2850 customers (versus a target of 2000) qualifying for the $300 utility bill rebate. This represents a 100% increase over the participation level of 2001 (1,423 participants). Like the tune-up program, the upgrade program saw high levels of contractor participation; at 450, this represents 35% of all registered gas contractors in the service area. A third-party process and impact evaluation of the 2002 program is being planned for 2003 in collaboration with NRCan.

The program design for 2001 and 2002 estimated the average annual natural gas savings at 30 GJ per participant – reflecting an improvement from 60-65% AFUE for the old furnace or boiler being replaced to a minimum 90% AFUE for the new appliance. The Malatest evaluation of 2001 results included a preliminary energy savings impact estimate of 21 GJ per year based on limited participant billing records available at the time of the analysis. The Malatest report cautions that this estimate is based on a very limited amount of billing data (a full heating season of data was not available and regional differences in measurement billing periods existed). Similar to the tune-up program evaluation, the consultant has recommended that the billing analysis portion of the 2001 program evaluation be reviewed over a longer period to provide more data points. BC Gas plans to pursue this analysis in the second half of 2003 as a component of the 2002 program evaluation.

Evaluation report pertaining to this program: 2001 Residential DSM Campaign Evaluation, R.A. Malatest & Associates Ltd., November, 2002. Note: This report includes results from three residential DSM programs offered by BC Gas in 2001- the furnace tune-up, the heating system upgrade program, and the insulation/draft proofing program.

Commercial Energy Utilization Advisory

This program is being offered to larger Rate 3/23 and Rate 5/25 customers by the BC Gas Commercial Energy Services Group. The offer includes an initial benchmarking consultation and an onsite assessment of natural gas conservation and efficiency opportunities along with recommendations and estimated savings impact. A preliminary program evaluation conducted during 2002 indicates participating customers are very positive toward the program and that savings at customer premises as a result of the program are in line with original estimates. The results reported in the Summary of Savings table (below) reflect the impact of 12 of 66 completed assessments during 2002 for which savings have been confirmed by customers.

Evaluation report pertaining to this program: BC Gas Commercial DSM Evaluation, R.A. Malatest and Associates Ltd., September, 2002

5.0 SUMMARY OF SAVINGS

Program	Participants		Savings (GJ)	
	Target	Actual	Target	Projected
Residential				
Heating System Tune-up	20,000	45,000	60,000	135,000
Heating System Upgrade	2,000	2,850	60,000	85,500
Commercial				
Efficient Boiler (reported in 2001)	-	-	-	-
Utilization Advisory	22	12	20,000	19,200
Community Based Initiatives				
Destination Conservation	0	6	0	1,200
Municipal Workshops	6	6	NA	NA
Other Activities				
Research & Program Design	NA	NA	NA	NA
Total			**140,000**	**240,900**

Total Resource Cost Test and DSM Achievement Incentive Status

The Total Resource Cost Test ("TRC") is a measure of the net benefits of a utility's DSM programs. BC Gas uses the TRC test to quantify the costs and benefits of DSM programs during program design. The TRC test is an excellent tool for ranking competing programs. The test accounts for the cost of the measure, the promotional costs of the utility, any utility rebates to customers (if applicable), the avoided gas supply costs, avoided utility distribution and transmission costs, and program free-ridership. While individual programs may have a positive or negative TRC contribution, BC Gas calculates overall TRC impact on a 'portfolio' basis, that is, by examining the impact of the combined group of programs for the year. For the 2002 portfolio of programs (as identified in the table above), the TRC net benefit has been determined at $2.8 million.

Although the 1998-2000 Revenue Requirement Settlement (through 2001 by extension) incorporated a DSM Achievement Incentive to encourage BC Gas to pursue cost effective DSM, BC Gas' understanding is that this incentive does not apply to 2002. In those prior years, achieving savings from a threshold of 133,070 GJ up to 177,425 GJ would have resulted in an incentive to the company of 3% of Total Resource Cost (TRC) net benefits and a savings of 177,425GJ and above would result in an incentive of 5% of TRC net benefits. Based on a calculated TRC net benefit of $ 2.8 million for the portfolio of programs identified above for 2002, this incentive amounts to $140,000. Although the Achievement Incentive is not available for 2002, BC Gas contends it has made significant progress in the development and execution of demand side programs as demonstrated by the high customer participation rates, high trades participation rates and significant energy savings levels indicated in the above table.

Greenhouse Gas Reduction

In its residential rebate offers in 2002 BC Gas indicated to participating customers its intent to record resulting emission reductions for credit to BC Gas' Greenhouse Gas Management program. BC Gas is not aware of any participant expressing an objection to this element of the programs. The net impact of the residential program savings is approximately 11,000 tonnes CO_2e (metric tons of carbon dioxide equivalent); the net impact of all 2002 programs is approximately 12,000 tonnes CO_2e.

Customer Safety Impact

An important, albeit secondary, impact of DSM programs that address gas appliance issues is the prospect of improvement in customer safety. BC Gas has made it a condition of participation that customers engage the services of a contractor properly registered with the provincial Gas Safety Program. In cases of equipment or appliance upgrades, BC Gas requires that the participant provide a copy of the requisite gas permit. The Gas Safety Program has acknowledged BC Gas' role in insisting on contractor compliance. While quantification of safety improvements as a result of these programs is not possible, BC Gas has received anecdotal advice from customers indicating that participation in the heating system tune-up measure led to the discovery of faults that could have had safety implications if left unattended – in one case the customer sent in photographs of a severely corroded heat exchanger discovered by his tune-up contractor that could have been discharging products of combustion (including carbon monoxide) into the home.

6.0 SUMMARY OF COSTS

Program and administrative costs as well as customer incentive costs remained below allowed levels in 2002:

	($000)	
	Allowed	Actual
Administration, marketing and research (DRIA)	$1,624	$1,444
Customer Incentives (Deferred)	$1,585	$1,227

As indicated in BCUC Letter No. L-12-02, BC Gas has deferred the DSM O&M spending below the allowed level of $1.624 million for return to customers.

Malatest & Associates Ltd.

BC Gas Commercial DSM Evaluation

FINAL REPORT

Prepared for
BC GAS

Prepared by
R.A. Malatest & Associates Ltd.

September 2002

EXECUTIVE SUMMARY

Highlighted below are the key findings associated with the review of the BC Gas Commercial DSM program. Information in this study is based on a review of BC Gas documentation, a telephone survey of a sample of participants (11) and non-participants (9 individuals – 12 projects), and on-site reviews (3) by engineers to verify estimated energy savings.

Program Design Issues

In general, customers were satisfied or very satisfied with the various processes associated with the Commercial DSM program, including the initial benchmarking activity, the site visit, the energy assessment report and use of the fax-back form to report activities completed. In general, nine in ten customers were satisfied or very satisfied with the specific processes, although there were slightly lower levels of satisfaction with the level of detail in the assessment report (79% satisfaction). Some customers requested that the energy assessment report contain more information and/or information more specific to their industry.

Program Monitoring Issues

Overall, it appears that BC Gas customers will not always implement planned activities as indicated on the fax-back feedback forms. Conversely, BC Gas may not be capturing the full impact of the program as some “non-participants” (those individuals who did not return the fax-back form) had actually implemented some of the recommendations provided by BC Gas. In addition, participants noted that they had continued to implement additional measures since the time of the fax-back form. In this context, BC Gas may wish to enhance program monitoring and follow-up to better identify actual GJ savings.

Validity of BC Gas Estimated GJ Savings

Overall, it appears that BC Gas’ estimated energy savings are reasonable and valid estimations of the expected energy savings. In a detailed analysis of three sites, the estimated savings as calculated by independent engineers were within 5% of the aggregate savings claimed by BC Gas. It should be noted that there were, however, considerable variations across projects, such that the mean absolute variation was 22.0%. Given the considerable difficulty in computing the actual energy savings, BC Gas may wish to change the manner in which potential energy savings are communicated to customers (use of typical “payback” periods rather than specific GJ estimates).

Estimated Impact of the Commercial DSM Program

Based on the telephone follow-up with both participants and non-participants, it was estimated that identified GJ savings were within 3% of BC Gas estimates. However, this impact includes a 9% over-estimate for participants (where BC Gas included an activity that was not actually implemented, due to a miscommunication between BC Gas and the customer) and a 7% under-estimate among non-participants (where BC Gas was not advised that an activity had occurred).

Most Respondents Agreed that Recommended Energy Savings Activities were Realistic.

Among both participants (64%) and non-participants (63%), a majority of respondents agreed or strongly agreed that the recommended energy savings activities suggested by BC Gas were realistic. Similarly, a significant proportion of respondents (42%) noted that the energy assessment led to their implementation of the technologies/processes earlier than they would have otherwise done so.

The Majority of Respondents Noted that the Energy Assessment was an Important Element in the Implementation of the Energy-Saving Technologies/Processes.

Overall, more than one-half (53%) of respondents felt that the energy assessment was important or very important in terms of the implementation of energy saving technologies and/or processes. Only one-quarter (26%) felt that the assessment was not important, while 21% of respondents assigned a neutral response to the importance of the energy assessment.

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SECTION 1: INTRODUCTION AND STUDY APPROACH

1.1 Program Description

In December 2000, BC Gas began a Commercial DSM program providing services to commercial customers to help identify potential savings on natural gas usage. This program was designed in response to a customer satisfaction survey, conducted in the same year, where customers indicated a keen interest for information on ways to conserve energy and reduce their costs. The Commercial DSM program is delivered through the Commercial Energy Services Group, which manages the relationship between BC Gas and approximately 6,500 commercial customers[1]. Commercial Energy Services currently has a staff of eight people and two consultants, however, over the past two years has only been able to dedicate a few resources to delivering the Commercial DSM program.

The Commercial DSM program was established in response to research that indicated many commercial customers generally lacked an understanding about the technical and economic potential for gas energy efficiency and conservation. In addition, customer research indicated that customers want BC Gas to provide advice on their current energy efficiency and opportunities for further energy-saving practices and/or technology.

In general, the Commercial DSM program consists of five key elements, including:

- benchmarking assessments;
- energy assessments (site visits and reports);
- case studies;
- database development; and,
- measurement.

A brief description of each activity is provided below:

a. Benchmarking Assessments

Benchmarking assessments are completed to help establish industry and/or sector “averages”. In this context, energy savings can be estimated and/or projected for specific projects by comparing current energy consumption (on a unit or standardized basis) for a particular project/organization against the industry/sector average.

b. Energy Assessments

Energy assessments can be viewed as a primary function of the Commercial DSM program. Energy assessments entail site visits by BC Gas staff to review existing energy applications, and identify potential technologies/processes to be implemented that could lead to energy savings. Staff follow up on the assessment by sending information/recommendations to the organizations’ project contacts.

[1] This group excludes large industrial customers.

c. Case Studies
BC Gas has developed five case studies profiling typical applications/activities that have resulted in energy savings. Case studies are intended to be an educational/promotional mechanism to attract the interest of commercial customers in terms of pursuing energy-saving options/processes.

d. Database Development and Measurement
BC Gas established a measurement system whereby predicted and actual gigajoule (GJ) savings are tracked. The database takes into account correction factors, such as weather.

In addition, BC Gas also provides a newsletter to its commercial customers as part of the Commercial DSM program.

1.2 Key Program Objectives

The DSM program is designed to yield the following benefits:

- Assisting BC Gas commercial customers to reduce their gas usage in ways which are most cost-effective for both the utility and their customers;
- Reducing greenhouse gas emissions and creating other associated environmental benefits;
- Raising awareness within the commercial sector about the benefits of demand-side management; and,
- Demonstrating leadership by BC Gas.

Currently, BC Gas does some evaluation of energy assessment site visits through the use of an Energy Assessment Feedback Form. The feedback form provides basic information as to the perceived utility of the energy assessment as well as the extent to which suggested changes have been or will be implemented. On the basis of the fax-back feedback form, BC Gas estimates the energy savings associated with the Commercial DSM program.

1.3 Research Overview

To review the extent to which the estimated energy savings can be attributed to the program, BC Gas requested an external evaluation of the Commercial DSM program. The key objectives of the study are as follows:

- To identify the extent to which BC Gas estimates of energy savings were valid and appropriate;
- To ascertain the extent to which data provided in the fax-back form reflect actual customer activity (i.e., were the proposed actions actually implemented?); and,
- To identify the strengths and weaknesses of several specific activities, including:
  - The initial benchmarking activity;
  - The site visit process;

- The energy assessment report; and,
- The fax-back feedback form.

It should be noted that due to the limited scope of the evaluation, the Consultant did not evaluate all components of the program. For example, the Consultant did not review the effectiveness of the case study activities, nor did the Consultant review the impact of the newsletter provided to commercial customers.

The research consisted of two main components: a customer satisfaction and implementation analysis and a technical review of energy savings. A description of the evaluation activities is contained in Section 2 of this report.

1.4 Glossary of Terms

Site Visit — Site visit refers to the inspection of the organization by BC Gas to review activities and identify potential energy saving activities. Inspections typically took between one to two hours.

Energy Assessment — A detailed report provided to Commercial customers after BC Gas staff had completed a site visit. These reports identified energy-saving activities and expected GJ savings.

Fax-back Feedback Form — This was the form sent to those organizations that received an energy assessment to ascertain the extent to which they had implemented the recommended changes. These forms were intended to be faxed back to BC Gas to provide BC Gas with an understanding as to what recommendations had been implemented and/or were likely to be implemented in the future.

Participants — Those organizations that had indicated on the fax-back form that they had implemented or planned to implement one or more of the BC Gas recommendations.

Non-Participants — Those organizations that did not indicate whether they had implemented or planned to implement one or more of the BC Gas recommendations (i.e. the fax-back feedback form was not returned, or was returned with no changes identified as having been implemented or were intended to be implemented).

On-site Review — The visit to an organization by the consulting engineers to verify the extent to which identified actions had been implemented and to assess the extent to which BC Gas estimates of potential energy savings were realistic.

SECTION 2: TECHNICAL ASPECTS

The research methodologies applied in the *Evaluation of the BC Gas Commercial DSM Program* included a technical review of energy assessment results, on-site reviews and a telephone survey of organizations that were involved in the energy assessment component of the BC Gas Commercial DSM program, including both participants and non-participants. The scope of work and research-related activities completed by the research team are detailed in this section.

2.1 Evaluation Approach and Scope of Work

The research team consisted of research analysts with specific evaluation experience, a research assistant and two engineers[2] with extensive experience in energy-related evaluations and audits.

The evaluation of the program incorporated both process and summative (impact) measures. Key issues explored in the research included:

- Process Elements
  - customer understanding of the program;
  - ease of participation in the program;
  - satisfaction with service/support provided; and,
  - identification of potential program enhancements.

- Impact Elements
  - identification of the extent to which clients/customers implemented or planned to implement specific improvements identified in the energy assessment conducted by BC Gas; and,
  - verification of estimated energy savings associated with suggested energy efficiency improvements.

BC Gas considered a range of approaches for the evaluation of the Commercial DSM program, including: basic analysis of customer satisfaction and implementation of energy efficiency improvements, technical review and validation of estimated energy savings, administrative data analysis, and an incremental analysis through the use of comparison or control populations. The final evaluation methodology included:

- Survey of organizations that participated in the site visit component of the program to determine customer satisfaction and the extent to which organizations had implemented or planned to implement suggested energy saving improvements identified through energy assessment activities;

[2] The two engineer experts on the research team were Bob Landell, A.Sc.T of Avalon Mechanical Consultants Ltd., and John Forster. P. Eng. of John Forster Enterprises.

- Technical Review of energy assessments and estimated savings conducted by BC Gas representatives; and,
- Engineer On-site Reviews to verify energy assessment estimates.

Specific research activities are described in detail below.

2.2 Survey Component

A number of activities were completed in the survey component of the research. The following list is a summary of these activities:

- design of the survey instrument in consultation with the BC Gas project team;
- development and mailout to organizations of an information letter explaining the research;
- sample preparation activities;
- training and debriefing sessions with surveyor;
- field test of the survey instrument;
- full survey administration;
- preparation and submission of two survey status reports; and,
- data cleaning, compilation, and analysis.

2.2.1 Review and Revision of the Survey Instrument

The Consultant developed a questionnaire to be administered to organizations that had participated in the site visit part of the program. The survey questionnaire was reviewed and modified to meet the research objectives, incorporating suggestions from the program team at BC Gas until a finalized version of the survey instrument was approved.

The survey instrument consisted of three main parts:

- Section A) implementation of recommended energy saving improvements
- Section B) program satisfaction
- Section C) program impact (importance of the energy assessment in terms of customer adoption of energy-efficient technologies/processes)

In the first section of the survey, each respondent was asked about the implementation status of a unique list of energy saving improvements that had been recommended by BC Gas in the energy assessment. The program satisfaction and program impact sections remained the same for all participants. A copy of the survey instrument is contained in **Technical Appendix C.**

2.2.2 Sample Preparation Activities

BC Gas provided administrative information, including contact and energy assessment details, for organizations that participated in the on-site energy assessment component of the Commercial DSM program. Administrative information was provided for 69 organizations. Only those organizations (35) that had been sent a fax-back feedback form by BC Gas to fill out were included in the survey sample frame.

Two groups were identified in the final sample frame, as follows:

- ***Program participants:*** organizations that participated in the energy assessment site visits and submitted a fax-back feedback form to BC Gas indicating that they were immediately completing or planning to complete at least one of the recommended activities.
- ***Program non-participants:*** organizations that participated in the energy assessment site visits but did not submit an energy assessment feedback form to BC Gas, OR submitted a feedback form indicating that none of the recommended activities would be implemented.

The final sample frame of 35 consisted of 15 participants and 20 non-participants. All 20 non-participants were invited to participate in the survey, even though feedback forms were not available for 10 organizations.

2.2.3 Design and Mail-out of Information Letters

A letter was developed to inform potential respondents in the sample frame, including a description of the project and its purpose, the protection of privacy and confidentiality of the information provided, and contact information for relevant staff from BC Gas Utility Ltd. and R.A. Malatest & Associates Ltd. The letter was mailed to all 35 potential survey participants. A copy of the information letter is contained in **Technical Appendix C.**

2.2.4 Survey Administration

The information letters were mailed out beginning on April 26, 2002. Full survey administration commenced on May 6th and was completed on June 7th. Reliability of the survey data collected was enhanced by the fact that one surveyor made all calls and survey completions. A listing of respondents by group is highlighted in Table 2-1.

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Table 2-1
Sample Characteristics & Response Rates
BC Bas Commercial DSM Evaluation

Issue/Area	Participants	Non-Participants	Total
Original Sample Frame (Projects)	**15**	**20**	**35**
Number who provided data for:			
– Section A: implementation of recommendations	11/12[1]	8/12[2]	20/24[3]
– Section B/C: Program Satisfaction/Program Impact Issues	11	8[4]	19
Gross response rate (project basis)	80%	60%	69%

[1] verified savings for 11 projects surveyed by telephone plus one additional property that was visited by engineers, for a total of 12 sites. Answers to the survey were provided by 11 participants.
[2] information was collected for 12 projects, however, faxback forms were not provided for four projects so it was not possible to verify what recommendations were implemented for these projects. Out of the 8 project sites with information for Section A, the Consultant actually spoke to 6 people (1 contact was responsible for 3 projects and responded to Section A for each project.
[3] Twelve participant sites and 8 non-participant sites had data with respect to implementation of activities.
[4] Information for Sections B and C was collected for 8 non-participants (comprised of the 6 non-participants who answered Section A, plus 2 non-participants who were not asked Section A, as no faxback forms were available).

Implementation status was collected for 20 projects and 19 surveys (one of the 12 participant sites did not complete a survey) were completed. For some of the sites included in the administrative data provided by BC Gas, the same contact person was listed. In these cases, the person responded to Section A of the survey for each of the sites, however, their responses to Sections B and C were recorded only once.

2.3 Technical Review of Energy Savings

Engineering members of the research team reviewed the energy savings estimates identified by BC Gas staff to ascertain the extent to which validation of the estimates could be completed through a review of the administrative information. The technical review considered whether or not the suggested changes to improve energy efficiency would lead to the predicted savings within a reasonable margin of error. The documentation available for organizations involved in the energy assessment component of the program was reviewed to determine the need for on-site reviews/case studies to establish the validity of energy savings. On the basis of the technical review, the engineers could not establish the accuracy of the estimated savings made by BC Gas. It was therefore recommended that the engineers complete on-site reviews to verify the validity of the BC Gas estimates.

2.4 Completion of On-site Reviews to Validate Energy Savings

Completion of three on-site reviews with program participants provided a further independent validation that the installed technologies would have resulted in the estimated GJ savings. On-site reviews were completed with individuals/representatives from the following organizations located in Vancouver, BC:

- **Participant 1:** manufacturer of food and beverage products.
- **Participant 2:** apartment-style condominiums consisting of 56 units.
- **Participant 4:** industrial products producer.

Based on the engineers' on-site reviews of the actual technologies in place after BC Gas' site visits, engineering estimates were completed for the three projects identified above and compared with original BC Gas assessment estimates. The case study report is contained in **Technical Appendix B.**

2.5 Research Limitations

It should be noted that due to the limited scope of the evaluation, the Consultant did not evaluate all components of the program. For example, the Consultant did not review the effectiveness of the case study activities, nor did the Consultant review the impact of the newsletter provided to commercial customers.

It should be emphasized that the goal of the research was to identify the extent to which BC Gas estimates of energy savings were appropriate, as well as to identify the client satisfaction with the program. Given the limited scope of the evaluation, no billing analysis was completed to verify energy savings. Billing analysis would require detailed information as to industrial activities (output/production) on a pre/post basis to more accurately assess the impact of changes in technologies and/or processes.

SECTION 3: IMPLEMENTATION STATUS

A key element of the phone survey and the on-site reviews was to identify the extent to which participants had actually implemented the recommendations that they had noted on the feedback form that they would be doing either immediately or in the next twelve months. In addition, telephone surveys were completed with non-participants (12 projects) to identify whether non-participants had in fact implemented any of the recommendations provided by BC Gas.

Data for this section of the report has been used to identify the extent to which BC Gas commercial customers "follow through" on their planned activities in terms of implementing the recommended changes. For participants, this analysis involves a comparison of the data provided on the fax-back form relative to information collected during the phone survey.

3.1 Participant Implementation Status

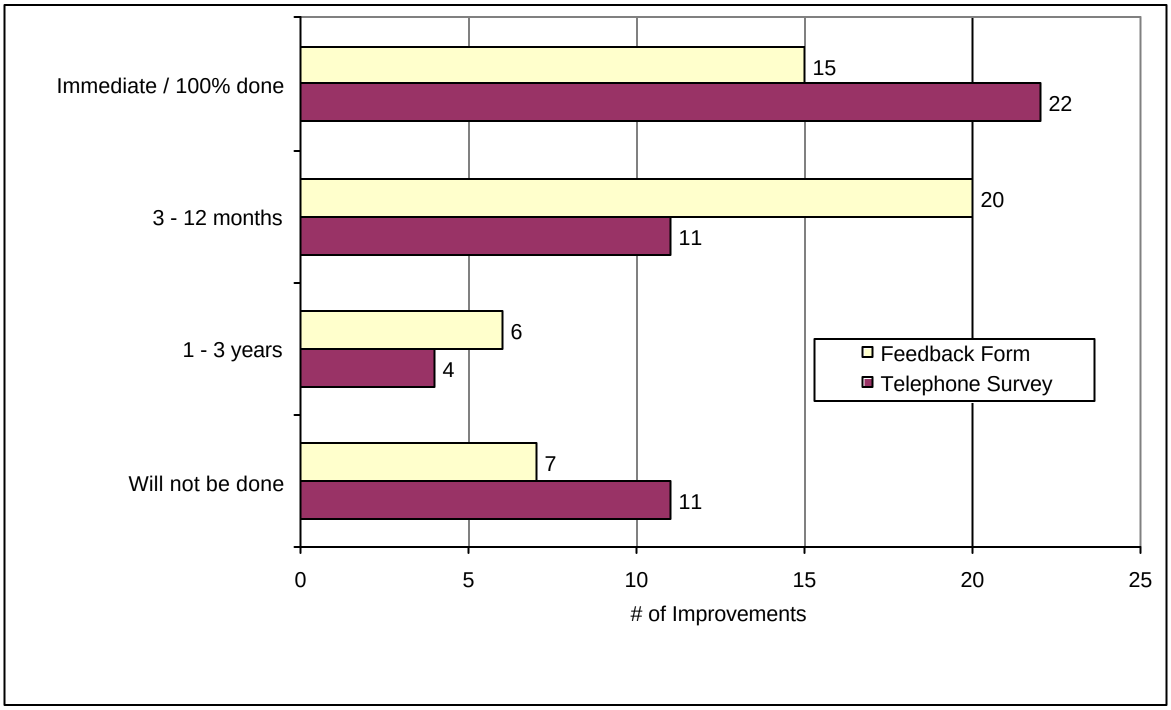
On the basis of telephone surveys with 11 participants, it appears that most (87%) of the actions/recommendations that were identified as "immediate" implementations were actually implemented by the time of the survey. In addition, the results of the telephone survey suggest that customers had continued to implement further recommendations, such that the total number of recommendations implemented at the time of the survey totalled 22. Detailed in Table 3-1 is the status of proposed changes among BC Gas participants.

Table 3-1
Status of BC Gas Recommendations/Changes
BC Gas Participants

Number of activities noted as "immediate completion"	
– on initial fax-back form (by the customer)	15
– confirmed by Malatest at the time of the survey	13
Additional activities completed since fax-back form completion	9
Total changes/recommendations implemented (at time of telephone survey)	22

Highlighted in Chart 3-1 is the status of all recommended changes as indicated at the time of the submission of the fax-back form and at the time of the telephone survey (i.e. about a one-year time span).

Chart 3-1
Status of Proposed BC Gas Recommendations/Changes
Participants[1]



n=48 (i.e. number of recommended changes) – Participants only (changes as listed on fax-back forms)
Note: "Don't know" responses are not displayed.
1. The categories listed on the faxback feedback form were Immediate, 3-6 months, 6-12 months, 1-3 years, and Unlikely to Implement. The categories listed on the survey form were 100% complete, Partially complete, To be implemented within 3 months, To be implemented within 4 to 12 months, To be implemented within 2-3 years, and Will not be done. Therefore, for the purposes of this chart, categories have been modified into 4 new categories that cover all of these.

Of note in Chart 3-1 is the increase in the number of improvements that respondents said would not be done between the time of the feedback response and the time of the telephone survey. By the time of the telephone survey, there had been an increase in the number of improvements that respondents reported would not be completed.

Cost was most cited as a reason for not implementing energy improvements that had been recommended by BC Gas. The following response from a non-participant reflects this.

> *"We had to take the cost of implementation into consideration. The areas identified would not have produced great savings."*

In five instances, it was the recommendation of using a pool cover that was rejected. In each case, respondents felt that the cost of such an installation would outweigh the benefits, as is summarized in the following non-participant's response.

> *Regarding the pool cover, I feel there is a larger cost involved than the savings it would bring. There is the large capital cost of the cover, the short life (2 years) of the cover itself, the increased costs of extra staffing, etc. It just isn't worth it for the money.*

Fifteen improvements were to be implemented immediately at the time of the feedback form responses, but 22 had actually been completed by survey administration time. As organizations were implementing the proposed changes (both immediate and within the next few months) it was not surprising to see an increase in the number of completed recommendations (i.e., number of activities listed as 'immediate' or '100% done' increased from 15 to 22), and a decrease in the number slated to be implemented in the next three to 12 months (from 20 to 11).

3.2 Non-Participant Activity

Similar to program participants, non-participants were also contacted by telephone to identify the extent to which they had implemented one or any of the recommended changes/activities suggested by BC Gas. Of the eight projects for which fax-back forms were available to the Consultant, three organizations had implemented at least one of the recommended changes/activities suggested by BC Gas. As highlighted in Table 3-2, of the 29 recommended actions/changes suggested by BC Gas, 3 (10%) had been implemented at the time of the survey and a further 5 (17%) were in the process of being implemented.

Table 3-2
Status of Proposed Recommendations
Non-Participants

Number of recommendations/actions noted as:	Number	% of Total
100% complete	3	10%
Partially complete	5	17%
To be implemented within 3 months	1	4%
To be implemented within 4-12 months	4	14%
To be implemented within 2-3 years	5	17%
Will not be completed/Unknown status	11	38%
Total	**29**	**100%**

Based on data supplied for eight projects.

3.3 Estimated Total GJ Energy Savings

As part of the study, the Consultant was asked to identify the extent to which BC Gas recommendations were implemented. The estimated GJ savings presented in this section are based on BC Gas' estimates[3] of potential energy savings. In effect, this analysis identifies the extent to which participants and non-participants implemented the recommended changes/technologies as identified in the BC Gas energy assessment report.

[3] Analysis completed for Section 4 of this report indicates that BC Gas estimates are within 5% of the likely actual energy savings based on an engineer's assessment of specific recommendations for three projects.

As indicated in Table 3-3, the majority of the energy savings resulted from the implementation of changes by the participant group, who had an estimated GJ savings of 36% of the total participants' potential savings estimated in the energy assessment. In addition to the GJ savings reported by the participant group, three organizations in the non-participant group had implemented a total of three recommendations, resulting in additional savings of 720 GJ per year (a total of 7% of the non-participants' total potential savings).

Among participants, most noted that they had indeed implemented the activity that they had indicated on their fax-back form would be undertaken immediately. As noted in Table 3-3, two organizations (Participant 4 and Participant 5) had made additional recommended changes that had not been indicated as activities to be 'immediately' completed on the fax-back form.

The one project that had not implemented any changes but had been noted by BC Gas as having energy savings was Participant 2. BC Gas had listed 2300 GJ savings associated with the installation of a high-efficiency boiler and low-flow shower heads. At the time of the engineering inspection, neither of the activities had been completed, although the management had noted that they would likely be installing a mid-efficiency boiler some time in the future. This discrepancy was due to a miscommunication between BC Gas and the customer.

Another participant reported that one of the recommendations was not implemented immediately, as indicated on the fax-back form, but indicated in the survey that it would be implemented in 4 to 12 months.

Overall, among the twelve participant files reviewed, it appears that on a net basis, BC Gas had overestimated the actual GJ savings by approximately 9% although the majority of this difference could be accounted for by one project (Participant 2).

As highlighted in Table 3-3, among non-participants, three (Non-Participants 5, 6 and 12) had actually implemented some of the recommendations from BC Gas. As BC Gas had not included any of these savings in its estimates of GJ savings, it appears that this would represent a 7% under-estimate of total non-participant energy savings generated through the implementation of recommended activities.

Combining data for both participant and non-participant surveys, the BC Gas estimate of total energy savings were within 3% of the identified savings based on the information obtained through the telephone survey. It should be noted however, that due to the lack of information with respect to the energy savings for some activities, the total energy savings would likely be very close to the total savings identified by BC Gas[4].

As detailed in Table 3-3, it appears that including both participants and non-participants, approximately one-third (29%) of the total recommended energy savings (as defined as total potential GJ savings) identified as part of the Commercial DSM project were implemented by BC Gas customers.

[4] For example, no values/data were available for some of the implemented recommendations associated with Participant 7 and Participant 11.

Table 3-3
GJ Savings by Respondents

Group	Potential GJ Savings Estimated by BC Gas[2]	GJ Savings Identified on Fax-back Form[3]	GJ Savings of Activities Confirmed by Malatest at Time of Survey[4]	% Difference (Survey vs. Fax-Back Form)	% of Potential Estimated GJ Savings[5]
Participant[1]					
1	3300	3300	3300	0%	100%
2	2500	2300	0*	-100%	0%
3	400	0	0	N/A	0%
4	2000	1150	2000	+74%	100%
5	1700	850	1800	+112%	106%
6	650	0	0	N/A	0%
7	6000	300	Unknown**	N/A	N/A
8	450	360	140	-61%	31%
9	2500	0	0	N/A	0%
10	6600	500	500	0%	8%
11	1750	1520	1520+***	0%	87%+
12	1500	1300	1300	0%	87%
Participant Total	**29,350**	**11,580**	**10,560+**	**-9%**	**36%**
Non-Participant					
1	730	0	0	N/A	N/A
2	257	0	0	N/A	N/A
3	563	0	0	N/A	N/A
4	1400	0	0	N/A	N/A
5	900	0	20	N/A	2%
6	700	0	200	N/A	29%
7	1700	0	0	N/A	N/A
8	550	0	0	N/A	N/A
9	Unknown****	0	0	N/A	N/A
10	Unknown****	0	0	N/A	N/A
11	950	0	0	N/A	N/A
12	1860	0	500	N/A	27%
Non-Participant Total	**9610**	**0**	**720**	N/A	**7%**
TOTAL	**38,960**	**11,580**	**11,280+**	**-3%**	**29%**

[1] Includes 11 surveys and one case study organization.
[2] Source: BC Gas' Benchmarking list.
[3] As associated with recommendations reported as being implemented immediately.
[4] As associated with recommendations reported as being 100% complete.
[5] GJ savings of activities confirmed by Malatest at time of survey divided by potential GJ savings estimated by BC Gas.
*At the time of the on-site review, no technologies had been installed, although the manager noted that they were planning to install a mid-efficiency boiler (GJ savings of 1470). This Participant was not surveyed by the Consultant but data was obtained through the on-site visit by the engineers.
**Respondent did not complete the action reported as Immediate on the faxback form, however, they reported that three other activities had been completed, but the GJ amount is unknown due to no values being supplied by BC Gas.
***One other action was completed but the GJ amount is unknown due to no value being supplied by BC Gas.
****GJ amounts are unknown because values were not supplied on the Benchmarking list by BC Gas.

SECTION 4: ACCURACY / VALIDITY OF BC GAS ESTIMATES

A key element of the evaluation was to ascertain the extent to which the BC Gas estimates of potential energy savings were valid. Inaccuracies in the claimed energy savings could occur due to a variety of factors, including:

- Participants not actually implementing the recommended initiatives even after they had noted on the feedback form that they would implement such actions ‘immediately’;
- Estimated energy savings calculated by BC Gas were not accurate;
- Non-participants actually implemented recommended actions without providing such information to BC Gas.

To ascertain the accuracy of energy savings claimed by the BC Gas Commercial DSM, the engineering members of the research team conducted a technical review of the BC Gas energy assessment reports and three on-site reviews to examine the energy savings estimates made during the on-site energy assessment visits. The results of the technical review suggested the need for further verification activities to be conducted on-site. The Technical Review Report is contained in **Technical Appendix A.**

Three sites were visited to review the BC Gas estimates of energy savings. The On-Site Review Report is contained in **Technical Appendix B.**

4.1 Extent to Which Participants Actually Implemented Identified Actions

Based on a follow-up telephone call to verify the extent to which participants had actually implemented the identified actions, it appears that for the 11 program participants surveyed, almost all had actually implemented the actions/changes that they had noted on their fax-back form.

In addition, as detailed in Table 4-1, several organizations had implemented additional changes that were not identified in the original fax-back form as being ‘immediately’ completed. This is not surprising, given that time has elapsed between the fax-back form response and telephone survey, during which customers could have completed activities planned for ‘6-12 months’.

Table 4-1
Extent to Which Participants Actually Implemented Identified Actions*

	Number
Number of actions noted as completed (on initial fax-back data)	15
Number of those actions actually completed (verified by phone survey)	13
Additional activities completed since fax-back form	9
Total activities completed relative to initial fax-back data	22

*Those actions that were identified as being implemented by Participants on the original feedback form.
Source: telephone survey of Participants (n=11).

4.2 Accuracy / Validity of Participant Activity

In order to examine the validity of the data provided in the feedback form by program participants, the status of recommendations made on the form can be compared to the actual status of implementation of the same recommendations at the time of the telephone survey (i.e., if a respondent noted on the feedback form that they would implement a certain recommendation immediately, had it actually been done?). Thirteen (87%) out of 15 recommendations that were to be implemented immediately had actually been completed by the time of the telephone survey.

4.2.1 Technical Assessment of the Validity of BC Gas' Estimates of Potential Energy Savings

The analysis of the validity of the BC Gas estimates of potential energy savings occurred in two stages: a technical review of the estimated savings and on-site reviews to more accurately estimate likely energy savings. A discussion of these activities follows below.

Technical Review
Two engineers reviewed the documentation provided by BC Gas to identify the extent to which the estimated gas savings by BC Gas were realistic and valid. On the basis of the documentation review, the engineers were not able to provide an opinion as to the validity of the BC Gas estimates. In this context, the engineers recommended on-site reviews to validate BC Gas estimates.

On-site Reviews
The Consultant, in discussion with BC Gas officials, identified three sites that were deemed to be representative of participant project completions. The sites included two industrial projects and a condominium project. Engineers spent approximately four to six hours at each site reviewing the proposed recommendations. Across the three sites, the engineers reviewed the accuracy/validity of 10 recommendations provided by BC Gas.

Although there were differences in individual measures, the overall estimate of GJs saved was within 10% agreement for two of the projects. The condominium project did not achieve the BC Gas estimate because two of the measures were not implemented, and the proposed boiler selections were not high-efficiency units (i.e., the boilers had not yet been purchased but would likely be mid-efficiency units rather than the recommended high-efficiency units).

As highlighted in Table 4-2, based on a review of the actual technologies in place, an engineering estimate was completed for the three projects identified. Overall, while the estimated GJ savings for the three projects studied was within 5% of the estimated savings, the average absolute variation was estimated to be 22.0%. It should be noted that while for some projects (i.e. Participant 1) the estimated total GJ savings were 13.5% of the BC Gas estimate, there were considerable differences in the individual components (i.e. variation ranged from –100% to +350% in terms of the estimated savings for Participant 1).

In general, the engineers noted that while BC Gas estimates were defensible, it would be difficult to identify energy savings associated with energy monitoring activities[5]. In addition, the significant variance in estimates underscored the difficulties associated with attempting to develop accurate energy savings estimates based on a BC Gas site visit of one to two hours.

Table 4-2
Total Savings Estimate Comparisons

Site	BC Gas Total Savings Estimate[1]	Malatest Engineer's Total Savings Estimate	% Difference
Participant 1	3300 GJ	3745 GJ	13.5%
Participant 2	2500 GJ	0/1470 GJ*	-42.4%/NA*
Participant 4	2000 GJ	2200 GJ	+10.0%
Combined	7800 GJ	7415 GJ	-4.9%

Note: mean absolute variation was estimated to be 22.0%.
[1]Source: BC Gas' Benchmarking List.
*BC Gas had assumed installation of a high-efficiency boiler based on fax-back data. At the time of the on-site review, the customer was considering a mid-efficiency boiler. In reality, the GJ savings were 0 at the time of the on-site review although the engineers accepted that a mid-efficiency boiler would be installed sometime in the near future and assigned a savings of 1470 GJ to the project.

4.3 Summary of Findings – Accuracy of BC Gas Estimates

Highlighted below are the key findings associated with the accuracy of the BC Gas Commercial DSM energy savings.

Most Participants had Actually Implemented the Recommended Changes.

The results of the telephone follow-up survey suggested that of the 15 actions noted by participants on the fax-back feedback form as being implemented 'immediately', 87% had in fact been implemented at the time of the telephone survey. In addition, a further nine actions had been implemented since the return of the fax-back form.

[5] BC Gas typically indicated that a 5% energy saving could be attributed to energy monitoring activities. While the engineers noted that this was possible, in practice, based on their (engineers') experience, monitoring is not consistently applied.

Engineering Estimates of BC Gas Energy Savings were Within Acceptable Ranges.

Overall, the results of the on-site reviews suggest that BC Gas estimates were within ±5% of the actual savings for the three projects visited. However, the mean absolute deviation was considerable (22%) which highlights the difficulty in developing accurate estimates of likely energy savings based on the short time (1-2 hours) that BC Gas representatives had to complete the site visit.

There are Other GJ Impacts That will Continue to Occur.

The follow-up telephone survey noted that some actions were implemented after the completion of the fax-back form. In addition, some organizations plan to implement further recommendations within the next 12 months or less.

"Non-participants" May Implement Some Activities at a Later Date.

It should be noted that there was some energy savings among "non-participants". While these savings were estimated to be only 7% of the identified savings for non-participants, it does indicate that the program will have an impact even among organizations that do not provide feedback after the initial follow-up (i.e., fax-back form).

Potential Application of Research Results

In review of the data, it was found that:

- among participants, of the total identified potential GJ savings, participants implemented activities which represented 36% of participants' total potential savings;
- among those organizations classified as "non-participant', there is some modest savings (approximately 7% of non-participants' total potential savings);
- overall, it appears that the estimated savings are within 5% of the claimed savings, although there is a considerable variation on a project by project basis.
- In projecting likely energy savings, BC Gas could utilize the following formula:

  ((Participants total potential GJ savings x .36) + (Non-participants total potential GJ savings x .07)) x .951.

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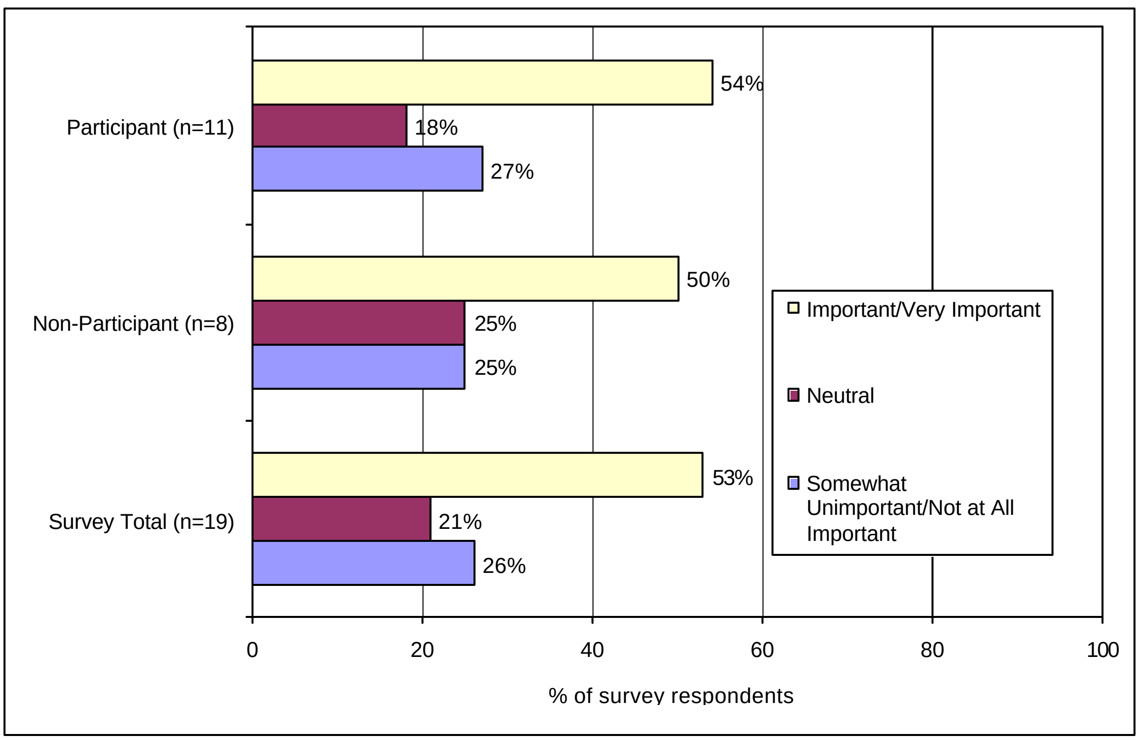
SECTION 5: IMPROVED AWARENESS OF ENERGY SAVING TECHNOLOGIES

Of the total survey participants, 54% indicated that the energy assessment was either important or very important to their organization's implementation of the recommended energy-saving activities. Levels of importance relating to implementation are illustrated in Chart 5-1. Of the participants (27%) who indicated that the energy assessment was not important to implementing the energy-saving activities, one respondent commented that the energy assessment did not offer anything that they didn't already know. Another individual noted that it was difficult for an outsider to make suggestions or observations that were relevant to their business.

Chart 5-1
Importance of the Energy Assessment in Terms of Implementation of the Recommended Energy Savings



As highlighted in Chart 5-2, while 74% of program participants and non-participants noted that their participation in the process enhanced their awareness of energy efficiency strategies, and 68% have a better understanding of how energy efficiency could be improved, a lower proportion (37%) indicated that the program was the <u>primary</u> factor in exploring energy-saving technologies. However, as noted previously, more than one-half of participants reported the energy assessment as important to the implementation of the energy-saving activities. In this context, the energy assessment was an important catalyst in terms of encouraging customers to implement the identified energy saving activities.

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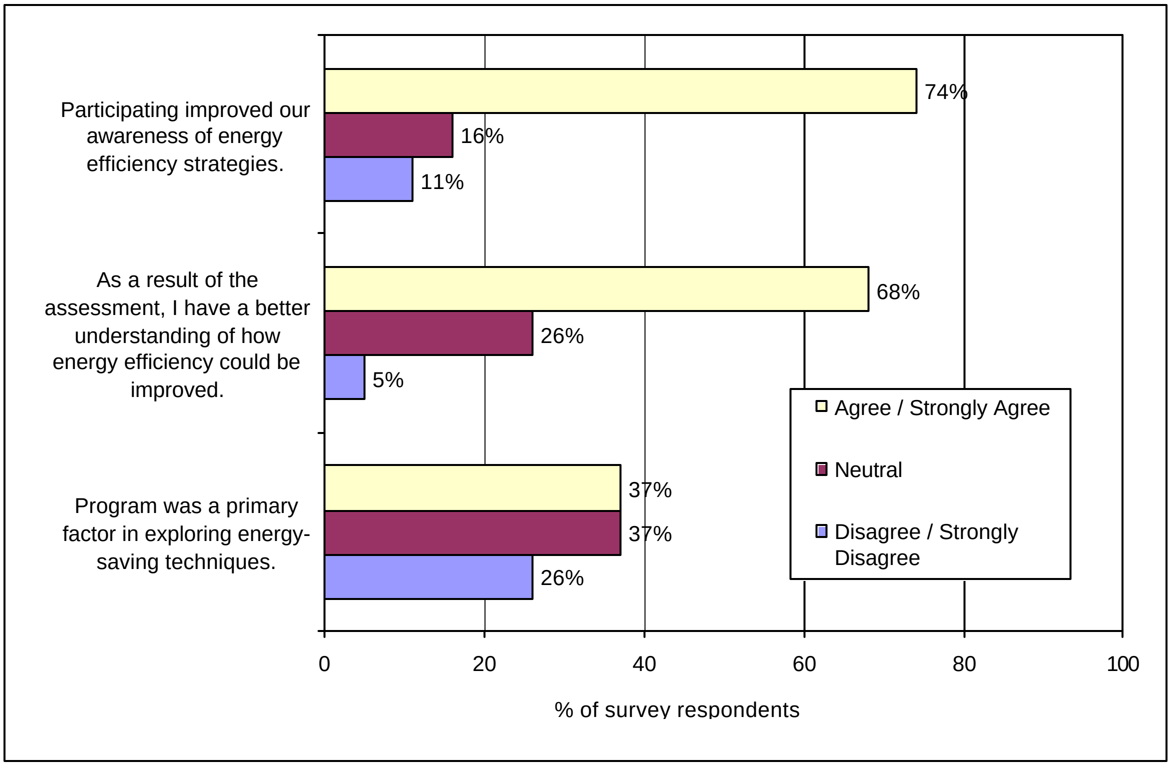
Chart 5-2
Respondent Awareness of Energy-Saving Technologies



n=19

The majority of respondents (79%) reported that the reason for participating in the energy assessment was to save money on energy costs. As one participant explained,

> *"Gas costs were soaring out of control. We were afraid we might have to close. We have 75 employees to consider. We approached the provincial government to get gas cost relief and came away knowing we were very much on our own. There was no interest in helping us."*

5.1 Additional Program Impacts

In addition to identifying the extent to which program participants (and non-participants) implemented the identified changes, survey data also provides useful information as to whether the energy savings as estimated by BC Gas had been met. It also indicates the extent to which respondents felt that the recommended energy savings activities were realistic and whether the assessment led to an earlier implementation of the recommended technologies/processes.

Table 5-1 reflects the level of agreement that respondents had with statements pertaining to the overall impact of the energy assessment on increasing energy efficiency within each organization. Of particular note, both participants and non-participants indicated fairly strongly (76%) that they were unsure whether energy savings estimated by BC Gas had been met. In fact, only 9% of participants and none of the non-participants agreed that they had been met. Three of the respondents commented that it was too early to determine how much had been saved. However, both groups did agree or strongly agree (63%) that the activities recommended in the BC Gas assessment were realistic for their organizations.

Respondents generally did not feel their organization was influenced to implement energy efficient technologies earlier by the BC Gas assessment. An average of 42% of respondents agreed or strongly agreed that the BC Gas assessment was influential to the implementation of energy efficient technologies. More participants than non-participants tended to agree or strongly agree.

Table 5-1
Respondent Opinion about BC Gas Energy Assessment Processes
Selected Issues

	Participants	Non-Participants	Total
Energy savings estimated by BC Gas have been met:			
% Yes	9%	0%	5%
% No	9%	10%	10%
% Unsure/Don't Know	82%	70%	76%
% Not Applicable	0%	20%	10%
Recommended energy savings activities made were realistic:			
% Disagree/Strongly Disagree	27%	13%	21%
% Neutral	9%	25%	16%
% Agree/Strongly Agree	64%	63%	63%
Assessment led to implementation of the technologies/processes earlier:			
% Disagree/Strongly Agree	18%	13%	11%
% Neutral	18%	38%	26%
% Agree/Strongly Agree	55%	25%	42%
% Don't Know/Not Applicable	9%	25%	16%

Note: Totals will not add to 100% due to rounding.

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SECTION 6: PROGRAM SATISFACTION

Survey respondents provided their opinions regarding a number of factors related to the design and delivery of the Commercial DSM program. Specifically, they were asked to rate their level of satisfaction with key elements of the BC Gas Commercial DSM program and with the program overall. They were also asked to suggest any improvements they thought could be made to the program. These results are reported in the remainder of this section.

6.1 Satisfaction with Program Elements

Results are reported for the following program components.

- Communication;
- Initial benchmarking conducted by the BC Gas representative;
- Site visit process;
- Energy assessment report; and,
- Fax-back feedback form.

A number of statements with agreement scales as well as open-ended responses indicated the respondents' level of satisfaction in these areas. In areas where satisfaction was low, respondents were asked to make suggestions for improvement. Summarized in Table 6-1 are respondents' levels of agreements with various statements about the different program elements.

Table 6-1
Client Satisfaction by Program Component
All Respondents

Program Element	***% Agree/Strongly Agree or % Yes***
Communication	
Any questions about the program were promptly addressed by BC Gas staff.	95%
Program objectives were clearly explained to me.	90%
Benchmarking	
Satisfaction with the initial benchmarking activity.	95% (% Yes)
Site Visit Process	
The time required by BC Gas to inspect our operations was not a barrier to participating in the energy assessment.	90%
Satisfaction with the site visit process.	95% (% Yes)
Energy Assessment Report	
The explanation of energy saving activities in the energy assessment report was straightforward and easy to understand.	100%
I received the energy assessment report within a reasonable amount of time after the energy assessment was conducted.	90%
Satisfaction with the energy assessment report.	79% (% Yes)
Sufficient level of detail contained in the energy assessment report.	79% (% Yes)
Fax-back Feedback Form	
The fax-back feedback (follow-up) form was an appropriate way for BC Gas to obtain information as to whether or not an organization implemented or intends to implement the suggested changes.	84% (% Yes)

BC Gas Commercial clients were satisfied with all aspects of the BC Gas Commercial DSM program. The key findings are summarized below:

- ***Communication:*** The majority the respondents agreed that BC Gas clearly explained the objectives of the program (90%) and promptly addressed any questions that they had (95%).

- ***Benchmarking:*** Almost all (95%) respondents were satisfied with the initial benchmarking activity that preceded the site visit.

- ***Site Visits:*** When asked if they were satisfied with the site visit process, 95% responded positively. Most clients (90%) agreed or strongly agreed that the time required for BC Gas to inspect their operations was not a barrier to participating in the energy assessment. One respondent felt that more time was required for the on-site assessment, as revealed by the following comment:

  "It would have been nice to have had more time with the BC Gas representative in order to bounce more questions off him about our current process."

- ***Energy Assessment Report:*** In general, respondents were satisfied with the energy assessment report that was provided to them after the site visit (79%). For those who were reportedly not satisfied with the report, limited practicality and lack of specific reference to their particular industry were cited as reasons for dissatisfaction. Approximately one-fifth of survey respondents indicated that there was insufficient detail contained in the energy assessment report. Comments to this effect include:

> *"It would be nice to get more data. Part of the report concluded that we should hire a consulting firm to get more help. This left us wanting more help but having to spend more money to get it."*

> *"I would have liked even more detail. They made two recommendations per property. I would have hoped for four or more - if there were that many that could have been made. I'm not sure if there were more verbal recommendations, aside from the ones in the report."*

- ***Fax-back Form:*** Most respondents (84%) felt that the feedback form was an appropriate way for BC Gas to obtain information about whether or not an organization implemented or intended to implement the suggested changes. The following comments were provided by those individuals who did not consider the feedback form to be appropriate:

> *"It would have been nice to have had a face-to-face meeting, instead of filling out the form. More than one person can be involved in the process after the first visit, and this would give everyone the opportunity to ask questions."*

> *"When you've already told them during the site visit that their suggestion was impractical, why did we need to get that?"*

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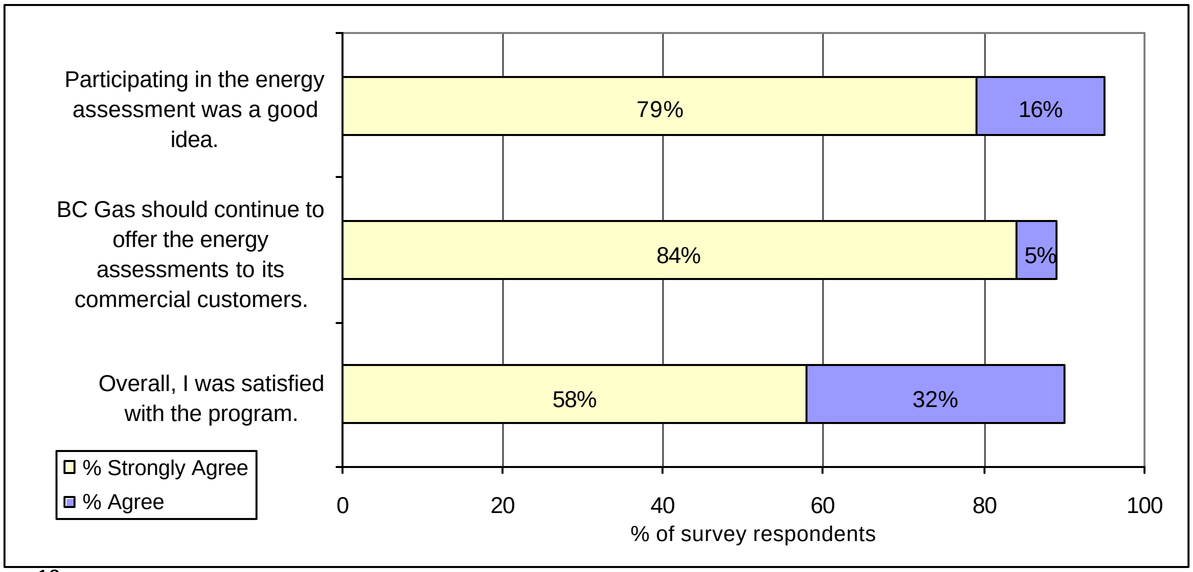
6.2 Overall Program Satisfaction

When indicating agreement with the statements regarding the impact of the program, the percentage of positive responses was consistently high, and this is shown in Chart 6-1. None of the respondents indicated that participating in the energy assessment was NOT a good idea.

Chart 6-1
Overall Program Satisfaction
% Strongly Agree / Agree



n=19

In addition, 18 out of 19 BC Gas commercial customers who participated in the survey agreed that a free energy assessment of their organization conducted by a BC Gas representative was a useful approach to encouraging energy saving activities by their organization, and that BC Gas should continue to offer energy assessment services to their commercial clients.

6.3 Suggested Program Improvements

At the end of the survey interview, respondents were given the opportunity to offer other suggestions for possible program enhancement.

Comments related to improvements that BC Gas could make for a more effective program were varied, but a few different themes did emerge. The most common suggestion was that BC Gas could offer incentives, rebates, or financial assistance in order to assist commercial customers in implementing their recommendations. This was mentioned by four of the respondents. Comments included the following:

> *"Organizations are concerned about spending money and taking risks. Organizations are concerned about paying up front. They would rather pay for the expenditures from savings earned. […] If BC Gas could help [us] get*

a loan for five years to make changes then the savings the changes produced could pay back the loan at virtually no cost."

- Non-Participant

"I would like to see incentives such as in the Power Smart program. Rebates would help with the cost of materials."

- Participant

"Upper management was skeptical about the validity of calculations on energy savings. An incentive program to kick-start improvements could help move them along. Without any incentive, there is skepticism to prove savings. If they monitored savings free for two years, that might encourage them to invest in the capital improvements and create trust in the process."

- Non-Participant

Respondents were also asked what other energy efficiency programs, if any, BC Gas should offer or explore with respect to its commercial customers. Although some clients did not know of any, several suggestions were made with a theme of financial assistance. Four respondents mentioned offering financing or financial incentives, and two others cited the cost of gas and the need for BC Gas to make a reduction in price. Some of these comments included:

"I would like to see incentive savings on consumption depending on participation in energy saving programs."

- Participant

"I would like to see financial incentives to get the process started. BC Hydro once gave credits for upgrading lighting. […] Incentives and rebates are especially important when dealing with third parties who need convincing to upgrade. It would also be beneficial if BC Gas monitored savings achieved over a two-year period on changes that were made to improve efficiency of energy usage. This would encourage people such as property owners to proceed with even more programs for energy savings."

- Non-Participant

"BC Gas needs to find ways to make gas cheaper. Homeowners, faced with expenses such as double-glazed windows and doors could use some help with cost of materials. BC Hydro had a program a while back where they came to homes to make them more energy efficient. That was a very good program and would benefit strata commercial consumers who bear some of these expenses individually."

- Participant

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SECTION 7: CONSULTANT'S OBSERVATIONS

Highlighted below are the Consultant's observations with respect to the evaluation of the BC Gas Commercial DSM Program.

Both Participants and "Non-Participants" were Very Supportive of the Program.

Overall, more than 90% of individuals who were involved in the program (i.e., had a BC Gas representative complete a site visit) were satisfied with the program. There was a high level of support for BC Gas to maintain and/or expand the program.

The Process was Acceptable to Customers.

In review of the key activities of the program (i.e. benchmarking, site visit, energy assessment, fax-back, etc.), it appears that customers were generally satisfied with the key elements of the program. It should be noted however, that some survey participants expressed the desire for the energy assessment report to include more detailed information.

BC Gas Should Enhance Follow-up Activities to Better Track Actions Taken.

It appears that while the fax-back form provided a general approximation of activities that would be completed, there is scope for BC Gas to increase follow-up to track the extent to which customers actually followed through on planned activities. This follow-up could be in the form of a telephone call or site visit, two to three months after receipt of the fax-back form.

Telephone follow-up with customers who did not complete and return the fax-back form could result in BC Gas being able to report additional program savings. For non-participants who were surveyed, the savings represented approximately 7% of the total potential GJ savings for this group.

While Estimated BC Gas Energy Savings are Defensible, BC Gas may Wish to Review how Such Savings are Presented to Customers.

As a result of the validation activities completed, the estimated actual savings relative to the BC Gas estimates were calculated to be within 5%, although the mean absolute variance was higher (22.0%). Based on the observations of the engineers, and given the difficulty in accurately defining potential energy savings based on a one to two hour site inspection, BC Gas may wish to change how potential savings data is presented to customers. Rather than present a specific GJ estimate, BC Gas could provide customers with a range of GJ savings and/or the likely "rate of return" (how long it would take for the energy savings to repay the cost of the technology) for the recommended actions.

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2001 Residential DSM Campaign Evaluation
Final Report

Prepared for
BC GAS

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Date: November 2002

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EXECUTIVE SUMMARY

BACKGROUND

As part of a series of Demand Side Management (DSM) coupon offers designed to encourage residential customers to improve energy efficiency, BC Gas initiated three programs in 2001 including a Furnace Tune-up coupon offer, a rebate on purchase of a high-efficiency natural gas central heating system (Heating System Replacement program), and a rebate on insulation and draft proofing materials (Insulation and Draft Proofing program) for residential customers.

The Furnace Tune-up program was offered from May 22 to September 15, 2001, and the Heating System Replacement and Insulation and Draft Proofing programs were offered between September 15 to November 30, 2001. The Furnace Tune-up program consisted of a $25 rebate on the utility bill upon completion of a furnace tune-up. The BC Gas Heating System Replacement program consisted of a $150 rebate for customers who replaced their heating system with a new natural gas high-efficiency heating system. Finally, the BC Gas Insulation and Draft Proofing program offered a $25 rebate for customers that upgraded their homes with $75 or more of energy saving materials such as ceiling insulation, weather stripping and caulking for exterior windows and doors.

This report highlights the findings of the 2001 Residential DSM Campaign Evaluation conducted for BC Gas by R.A. Malatest & Associates Ltd. This evaluation is based on a multi-faceted research approach including:

- *extensive surveys of program participants, including surveys with 333 Furnace Tune-up program participants, 181 Heating System Replacement program participants, and 145 Insulation and Draft Proofing program participants;*
- *survey with 557 non-participants[1];*
- *surveys with contractors that completed maintenance for the Furnace Tune-up (50) and Heating System Replacement (36) programs;*
- *survey with 11 manufacturers and distributors that participated in the Heating System Replacement program; and,*
- *administrative data analysis, including a pre/post analysis of changes in energy consumption due to the DSM Campaign.*

PROGRAM OVERVIEW

A total of 27,324 individuals participated in the Furnace Tune-up program, representing 4.2% of the BC Gas customer base[2]. In addition, there was a total of 1,423 participants for the

[1] Non-participants were defined as residential customers who did not apply or receive funding for any of the three BC Gas 2001 residential DSM programs.
[2] Based on 657,120 BC Gas customers in the Interior and Lower Mainland. Total number of customers in Lower Mainland is 450,289 and total number of customers in the Interior is 206,831. Data provided by BC Gas.

Heating System Replacement program and 1,607 for the Insulation and Draft Proofing program, representing 0.2% of the customer base in each of these programs.

In general, it appears that the program was successful in a number of ways. For example:

- 62% of Furnace Tune-up participants, 46% of Insulation and Draft Proofing participants, and 38% of Heating System Replacement participants reported that the rebate caused them to complete the maintenance or furnace replacement activity earlier than they would have otherwise;
- The rebate was described as important or very important in encouraging the maintenance activity by 45% of Furnace Tune-up participants, 38% of Heating System Replacement participants, and 36% of the Insulation and Draft Proofing participants;
- Contractors reported a 22% increase in the number of furnace tune-up inquiries, 30% increase in the number of heating system replacement inquiries, 19% increase in the number of furnace tune-ups, 38% increase in the number of natural gas high efficiency heating system replacements, and 8-16% increase in the number of maintenance activities completed as a result of the program.

Overall, there was almost universal endorsement of the various BC Gas DSM programs across all groups contacted. Almost 90% of the Furnace Tune-up participants, 87% of Heating System Replacement participants, and 78% of Insulation and Draft Proofing participants indicated that they were satisfied or very satisfied with the program. In addition, 74% of Furnace Tune-up contractors, 89% of Heating System replacement contractors, and 82%[3] of manufacturers and distributors indicated that they were satisfied with the program.

PROGRAM PARTICIPANT PROFILE

Analysis of the profile of program participants indicated that programs attracted significantly different populations. Specifically, while most Furnace Tune-up participants were 65 years of age or older, only 19% of Heating System Replacement participants were 65 years of age or older. Participants in the Furnace Tune-up program also reported lower household earnings compared to participants in other programs.

With respect to home ownership, nearly all participants owned their own home, in comparison to the BC population, where only two thirds of the population own their homes. Participants also tended to own older homes; relative to the 39% of homes in BC that were more than 25 years old, a much higher proportion of participants noted that their home was built more than 25 years ago (Furnace Tune-up – 46%, Heating System Replacement – 60%, Insulation and Draft Proofing – 64%).

[3] Representing 9 out of 11 manufacturers surveyed.

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PROGRAM DELIVERY AND ADMINISTRATION

A high percentage of participants and contractors reported that they found it easy to participate in the BC Gas DSM programs[4]. Slightly fewer manufacturers reported that program participation was easy or very easy (63%), and recommended providing more notice, running a longer program, and simplifying paper work.

In terms of the design of the program, while most Furnace Tune-up program participants felt that this $25 rebate offered by BC Gas was adequate, a minority of participants felt that the $150 Heating System Replacement and $25 Insulation and Draft Proofing rebate offers were adequate. The largest group of participants in these programs recommended a rebate of $377[5] for the Heating System Replacement rebate (or approximately 11% of the average heating system replacement cost reported by participants), and a rebate of $113 for the Insulation and Draft Proofing materials rebate[6]. Insulation and Draft Proofing participants recommended making this rebate proportionate to the amount spent by individuals on upgrade materials rather than a fixed rebate amount.

COMMUNICATION

The BC Gas 2001 Residential DSM Campaign was actively promoted by BC Gas through advertisements featuring Shell Busey in magazines, newspapers, retail stores, on radio and on their website, and through direct mail and bill inserts to customers. It appeared that BC Gas bill inserts were most effective in informing BC Gas customers about the DSM programs[7]. The largest group of participants for each program reported being made aware of the program through an insert in their BC Gas bill. Contractor awareness of BC Gas' advertising efforts varied, with Heating System Replacement contractors reporting lower levels of awareness of BC Gas marketing efforts such as bill inserts.

Several issues were raised with respect to program marketing and delivery:

- In general, participants and contractors noted that the BC Gas bill insert was the most effective way of providing information about the rebate to customers.
- A significant proportion of non-participants noted that they were not aware of the various rebate programs. This would suggest that BC Gas should continue to utilize multiple communications channels (bill inserts, newspaper advertisements, radio/TV) to maximize program awareness.
- Given the considerable differences in the profile of the various participant groups, there is scope to modify/adapt the communications program to better reflect the demographic characteristics of each program participant population. For instance, the communication

[4] Percentage of participants describing program participation as easy or very easy: Furnace Tune-up participants – 96%; Heating System Replacement participants – 89%, Insulation and Draft Proofing participants – 92%, Furnace Tune-up contractors – 82%, Heating System Replacement contractors – 89%, and Heating System Replacement manufacturers/distributors – 63%.
[5] Top two scores removed from the analysis.
[6] Or approximately 21% of the average cost of insulation and draft proofing materials.
[7] Specifically, 34% of Furnace Tune-up participants, 29% of Heating System Replacement participants and 28% of Insulation and Draft Proofing participants indicated that they became aware of the program through inserts in their BC Gas bills.

strategy could be modified to recognize the considerable range in education of participants in the various DSM programs[8].

ADMINISTRATIVE DATA ANALYSIS

There were a number of data issues that affected the administrative data analysis. Specifically, while the sample size used as part of the current study was substantial, only 50% of program participants were successfully matched to administrative (energy-use) data)[9]. As a result, it is possible that the characteristics of Furnace Tune-up participant households where administrative data was available may not be reflective of all Furnace Tune-up program participant households. In addition, at the time that this data analysis was completed, post-program energy-use data was limited (December 2001 to March 2002). Because one goal of the program was to improve energy awareness and to educate customers about other activities that could be completed to save energy, longer-term energy savings resulting from the program would not be captured using such a short window of time. Finally, differences with respect to how energy consumption is measured between Interior and Coastal customers may have affected the accuracy of the estimated energy savings from the DSM programs.

While the exact magnitude of energy savings resulting from the 2001 Residential DSM Campaign is difficult to ascertain due to issues associated with the administrative data, the current analysis found that households participating in the 2001 Residential DSM Campaign witnessed a marked decline in energy consumption relative to comparison households. Heating System Replacement participants witnessed a substantial decrease in energy consumption on a pre/post basis (estimated decrease in energy consumption of 18.2% compared to a 0.4% decrease among comparison households). Similarly, the savings in average energy consumption among Insulation and Draft Proofing participants (4.2%) was significantly different from the comparison population. While the analysis did not detect a statistically significant decrease in energy consumption due to the Furnace Tune-up program, utilization of a longer time period or increasing match rates may help to more accurately measure the impact of this program.

OTHER ISSUES

The BC Gas 2001 Residential DSM Campaign resulted in significant increases in inquiries, heating system replacements/tune-ups, and other maintenance work as reported by contractors. Specifically, contractors reported twenty to thirty percent increases in the number of inquiries, and 8% to 16% increases in other maintenance work resulting from the DSM Campaign. Contractors in the Furnace Tune-up program reported completing 19% more furnace tune-ups as a result of the program[10], and contractors in the Heating System

[8] Specifically, 18% of Furnace Tune-up participants reported that they did not have a high school diploma compared to 5% of Heating System Replacement participants and 6% of Insulation and Draft Proofing participants.
[9] This match rate is based on the Furnace Tune-up program participants.
[10] 50 contractors participating in the Furnace Tune-up program were surveyed.

Replacement program reported a 38% increase in the number of heating system replacements completed[11].

Manufacturers also reported a greater number of inquiries and sales of natural gas high efficiency furnaces. Two-thirds of manufacturers reported selling more natural gas high efficiency heating systems as a result of the program. In addition, manufacturers reported that the percentage of high efficiency heating systems (compared to mid efficiency systems) sold increased from 29% before September 2001 to 36% after September 2001.

With respect to free riders, the percentage of non-participants households completing furnace tune-ups, heating system replacements, and insulation/draft proofing maintenance is used to estimate the percentage of households that would have completed these activities in the absence of the 2001 Residential DSM Campaign[12]. Specifically, 28% of non-participants had completed a furnace tune-up between May 22 and September 15, 2001. In contrast, only 12% of non-participants reported upgrading their home with $75 or more of energy saving material between September 15 and November 30, 2001, and 2% replaced their furnace with a natural gas high-efficiency central heating system during this time.

With respect to free drivers, or additional energy saving activities completed by customers as a result of the program, one-quarter of Furnace Tune-up program participants reported completing or planning to complete at least one other energy-saving activity as a result of their participation in the program. A lower proportion of participants in the Heating System Replacement program (9%) or Insulation and Draft Proofing program (12%) indicated that their participation in the program resulted in the completion or planning of other energy efficiency measures. The most common free drivers included checking/installing weather stripping or replacing the air filter.

CONSULTANT'S OBSERVATIONS

Highlighted below are the Consultant's observations regarding the three BC Gas residential DSM programs.

- There is a high level of support for the programs. Notwithstanding the relatively modest incentives provided (i.e., $25 to $150), there was a very high level of support for these programs among program participants, contractors, and manufacturers. These programs were also supported in principle by a significant (65%) proportion of non-participants who noted that they would be willing to participate in future energy-savings programs.
- There is an element of "free ridership" in all three programs. Among non-participant households, a higher percentage of non-participant households reported completing a furnace tune-up (28%) compared to the percentage of non-participant households that either installed a new high efficiency furnace (2%), or upgraded their home with energy saving materials (12%).

[11] 36 contractors participating in the Heating System Replacement program were surveyed.
[12] In estimating free ridership, non-participants were asked whether they had completed the activities targeted as part of the 2001 Residential DSM Campaign (Furnace Tune-up, Heating System Replacement, and Insulation and Draft Proofing programs) between May 22 and September 15, 2001 (furnace tune-up) and between September 15 and November 30, 2001 (heating system replacement and insulation and draft proofing maintenance).

- Net Impacts Vary by Program. Use of administrative billing analysis that incorporates a control group provides an indication of the net or incremental impact of each program. While administrative data issues identified above affected the ability of the current analysis to measure the exact impact of each DSM program, the Heating System Replacement program had the greatest impact (average 18.2% decline in household energy consumption relative to the control group decline of 0.4%). The savings from the Insulation and Draft Proofing program was estimated at 4.2%, a statistically significant level of savings. Participation in the Furnace Tune-up program did not result in a statistically significant decrease in energy consumption, although the data limitations may have impacted the ability of the current analysis to detect savings for this program (further information about data limitations is provided in Section 7).

- Recommended Approaches that may Increase Data Reliability. Because of the data issues raised as part of the current study, the Consultant made a number of recommendations with respect to measures that could be taken to increase data reliability. Specifically, it may be possible to increase the ability of the current analysis to measure decreases in energy usage caused by BC Gas DSM programs by using a longer time period (e.g., possibly associated with additional applications of the program) or by improving match rates[13].

- Review Appropriateness of Rebates/Financial Incentives. The results of the survey suggest that while the $25 Furnace Tune-up rebate represented a significant portion (28%) of the total cost of furnace tune-ups, the $150 rebate for a new high efficiency heating system represented a much lower (5%) of the total share of the system replacement cost. Given the marked energy savings impact associated with the Furnace Replacement program, BC Gas may wish to review the amount of the Furnace Replacement rebate.

- Residential DSM Programs Have Other Positive Benefits. In addition to the estimated energy savings associated with the various programs, these DSM programs have several important benefits, including:
  - educational/information element(s). Contractors provided participants with information as to how to reduce energy consumption;
  - "free drivers". With respect to free drivers, participants in the Furnace Tune-up program were most likely to report completing or planning to complete at least one additional energy-saving activity as a result of their participation in the program (25%). Twelve percent of Insulation and Draft Proofing participants and 9% of Heating System Replacement programs participants also reported additional energy-saving activities as a result of these programs;
  - enhanced perception of BC Gas. A large majority of program participants reported being satisfied with the program, and almost all participants and a majority of non-participants noted that it was important for BC Gas to encourage its customers to practice energy efficiency. As a result, programs such as the 2001 Residential DSM

[13] Other measures, such as incorporating information from meter readings or conducting case studies to determine the effect of a furnace tune-up could be implemented; however, the cost of such measures could easily outweigh the possible benefits.

Campaign meet customer expectations with respect to BC Gas' role in encouraging energy efficiency.

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INTRODUCTION AND STUDY APPROACH

As part of a series of 2001 Demand Side Management (DSM) coupon offers designed to encourage residential customers to improve energy efficiency, BC Gas initiated three programs including a Furnace Tune-up coupon offer, a rebate on purchase of a high-efficiency natural gas central heating system (Heating System Replacement program), and a rebate on insulation and draft proofing materials (Insulation and Draft Proofing program). The Furnace Tune-up program[14] consisted of a $25 rebate on the utility bill upon completion of a furnace tune-up by a registered gas contractor between May 22 and September 15, 2001. The BC Gas Heating System Replacement program consisted of a $150 rebate for customers who replaced their heating system with a new natural gas high-efficiency heating system between September 15 and November 30, 2001. The BC Gas Insulation and Draft Proofing program offered a $25 rebate for customers that purchased $75 or more insulation and draft-proofing materials between September 15 and November 30, 2001.

The primary objective of these programs was to realize energy savings. Secondary objectives of the programs included energy awareness activities (servicing trades provided energy conservation message/advice to customers in those cases where service trades were contracted), transformation of the market-place to more efficient technologies and practices, and provision of assistance to customers in managing energy costs.

R.A. Malatest & Associates Ltd. developed and implemented six surveys to measure the process and impact of the three rebate offers. Specifically, surveys were completed with residential participants in all of the rebate offers, with non-participants[15], and with contractors that also participated in the Furnace Tune-up and Heating System Replacement programs (as well as manufacturers/distributors participating in the Heating System Replacement program). The results of this research will provide BC Gas with insight into customer perceptions about the process and impact of each coupon offer, and recommendations for improving subsequent initiatives.

The evaluation findings are presented in two sections:

A. Main Report: key findings and recommendations associated with the evaluation[16].

B. Technical Appendix: includes statistical tables, and copies of each of the six survey instruments, as well as respondent comments.

The findings of the 2001 Residential DSM Campaign Evaluation are presented in the following chapters:

- Research Objectives and Methodology

[14] Also referred to as the Summer Tune-up offer

[15] Defined as BC Gas residential customers who did not apply or receive funding for any of the three BC Gas rebate programs. Those customers who applied but did not qualify for the rebate were excluded from this group as well.

[16] Unless otherwise stated, the sample sizes associated with tables and charts presented in this report reflect the full sample base (Furnace Tune-up program participants – 333; Heating System Replacement program participants – 181; Insulation and Draft Proofing program participants – 145; Furnace Tune-up program contractors – 50; Heating System Replacement program contractors – 36; Heating System Replacement manufacturers/distributors – 11; and Non-participants – 557).

- Residential DSM Overview
- Program Participant Profile
- Program Delivery Issues
- General Satisfaction with the Program
- Estimation of Program's Impact
- Estimating the Net Impact of the Residential DSM Programs: Administrative Data Analysis
- Barriers to Participation
- Estimation of Free Rider / Free Drivers
- Energy Use, Practices and Perceptions
- Summary of Findings

In the preparation of this report, the following terms are used:

Participants	Residential customers that were approved for funding for one of the three BC Gas rebate programs.
Non-Participants[17]	Residential customers who did not apply or receive funding for any of the three BC Gas rebate programs.
Contractors	Licensed gas fitters who completed one or more summer Furnace Tune-ups or replaced one or more heating systems for customers as part of the 2001 Residential DSM Campaign.
Free Riders	Customers who would have completed maintenance in the absence of the BC Gas rebate program.
Free Drivers	Additional energy-saving activities completed by customers as a result of their participation in a BC Gas DSM program(s).
Comparison Group	For the administrative data analysis, energy consumption was compared between program participants and a comparison group. The comparison group consisted of non-participants that were matched to participant households on characteristics such as region and energy-usage profile[18].

[17] Those who applied but did not qualify for the rebate were excluded from this evaluation.
[18] Full information on the methodology used to define the comparison group is provided in Section 7.2.

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SECTION 1: RESEARCH OBJECTIVES AND METHODOLOGY

1.1 Evaluation Approach

R.A. Malatest & Associates Ltd. utilized a multiple lines of evidence approach to identify the impact of the Residential DSM Programs. Key elements of the evaluation included:

Extensive Surveys of Program Participants/Non-Participants
R.A. Malatest & Associates Ltd. completed extensive surveys with both participants and a representative sample of non-participants as part of this evaluation. Program participants were asked to identify their satisfaction with the program, other energy saving practices that they attributed to the program, and to detail the importance of the program in terms of implementing the identified changes. In order to ascertain the extent of "free ridership," a large sample of non-participants was included as part of the evaluation.

Surveys of Contractors/Manufacturers
In order to gain a better understanding of key program administration issues, extensive surveys of BC Gas contractors/manufacturers were completed. These surveys provided useful information as to contractor/manufacturer perceptions of the program.

Administrative Data Analysis
To quantify the actual savings that could be attributed to the program, the Consultant completed a detailed analysis of gas consumption for a representative period prior to and after program implementation. This pre/post analysis was based on the examination of aggregate energy consumption for 16,252 program participant households and 16,252 comparison (non-participant) households. Matching between comparison and participant households was completed on region and energy utilization profile[19]. The net difference in energy consumption between the two groups could be attributed to participation in one or more of the residential DSM programs[20].

[19] Households were not included in the administrative analysis if energy consumption data was incomplete over the pre-implementation or post-implementation period, if there was an address change, or if there was a change in the customer account. Further information about the matching procedure is provided in Section 7.2.
[20] Outliers were not excluded as part of the primary analysis presented in Section 7; however, Section 7.5 identifies the results of additional analyses in which where outliers were removed from the analysis.

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Survey Completions and Response Rates

As highlighted in Table 1-1 below, this evaluation was based on survey information provided by more than 1,300 individuals (participants, contractors/manufacturers and non-participants). As detailed in the Table, the study was characterized by high response rates among program participants (60.7%) and contractors/manufacturers (49.5%). Response rates for non-participants (41.5%) were slightly lower.

Table 1-1
Participant and Contractor Survey Administration Summary

	Sample	NIS/ Wrong Number	Non-qualifier/ duplicates	Valid Sample*	Refusal	Actual Completions	Valid Response Rate (%) **
Furnace Tune-up participants	562	13	16	533	46	333	62.5%
Furnace Tune-up contractors	120	2	13	105	6	50	47.6%
Heating System Replacement participants	303	3	0	300	12	181	60.3%
Heating System Replacement contractors	80	3	0	77	3	36	46.8%
Heating system manufacturers	15	0	1	14	0	11	78.6%
Home upgrade materials participants	288	30	6	252	17	145	57.5%
Sub-total:							
Participants	1,153	46	22	1,085	75	659	60.7%
Contractors/ Manufacturers	215	5	14	196	9	97	49.5%
Non-Participants	1,485	114	29	1,342	387	557	41.5%
Total	2,853	165	65	2,623	471	1,313	50.1%

*Sample less not-in-service/wrong numbers, non-qualifiers/duplicates. NIS = Not in Service
** Actual Completions/Valid Sample.

This report reflects data collected on samples of program participants, contractors and non-participants received by R.A. Malatest & Associates Ltd[21].

[21] Unless otherwise stated, the sample sizes associated with tables and charts presented in this report reflect the full sample base (Furnace Tune-up program participants – 333; Heating System Replacement program participants – 181; Insulation and Draft Proofing program participants – 145; Furnace Tune-up program contractors – 50; Heating System Replacement program contractors – 36; Heating System Replacement program manufacturers/distributors – 11; and Non-participants – 557).

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Based on the total numbers of participants, contractors and non-participants, the data collected have the following accuracy levels:

Table 1-2
Statistical Accuracy of Survey Data

	Furnace tune-up participants	Furnace Tune-up contractors	Heating System Replacement participants	Heating System Replacement contractors	Heating System Replacement manufacturers / distributors	Insulation and Draft Proofing participants	Non-participants
Number of participants	27,324	772	1,423	314	15	1,607	620,000*
Number of completions	333	50	181	36	11	145	557
Accuracy level**	±5.3%	±13.4%	±6.8%	±15.4%	±15.8%	±7.8%	±4.2%

* Estimate of number of non-participants based on number of BC Gas customers in Lower Mainland and Interior less the number of participants and those who applied but did not qualify for the rebate. Numbers provided by BC Gas.
** At the 95% confidence level.

1.2 Survey Activity

For the individual components of the Evaluation of the BC Gas 2001 Residential DSM Campaign, surveying was completed in four phases:

- For the Furnace Tune-up program, 333 participants were surveyed between July 14 and November 14, 2001. In addition, a total of 50 contractors were surveyed between July 25 and November 9, 2001.
- For the Heating System Replacement program, 181 participants were surveyed between February 28 and March 25, 2002. A total of 36 contractors and 11 manufacturers and distributors were surveyed between March 27 and April 22, 2002.
- 145 Insulation and Draft Proofing program participants were surveyed between February 27 and April 4, 2002.
- Finally, 557 non-participants were surveyed between April 11 and May 2, 2002.

Prior to survey administration, a number of activities were completed by R.A. Malatest & Associates Ltd.:

- development of the Participant, Service Trade and Non-participant survey instruments in conjunction with BC Gas;
- DASH-CATI[22] programming of the final questionnaires;
- uploads of participant, service trade, manufacturers / distributors and non-participant data into DASH;
- mail-out of cover letters;
- surveyor training; and,

[22] DASH refers to Data and Survey Handling (DASH) system. CATI refers to Computer Assisted Telephone Interview.

- survey field-testing.

Survey monitoring was completed by BC Gas representatives during field-testing, and was continued after field-testing by R.A. Malatest & Associates Ltd. survey managers and research staff.

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SECTION 2: RESIDENTIAL DSM OVERVIEW

2.1 Program Rationale

BC Gas conducted an advance survey with 379 BC Gas customers in the trade area (accuracy ±5%) from December 18 to December 21, 2000. The survey results showed that over half of respondents were interested in both a coupon program for home improvements (56%), and a coupon for a furnace tune-up (53%). One quarter of respondents were also interested in a $300 rebate off the cost of a new high efficiency furnace[23]. Over half of respondents who said they would be interested in the offers stated that all three offers made them feel more favourable about BC Gas. Most interested respondents also agreed that the offer would help save energy, and three quarters of interested respondents agreed that the offer showed that BC Gas was working with them to reduce the impact of rate increases.

2.2 Program History

The overall program was developed in consultation with furnace manufacturers, HVAC contractors and trade associations. The Furnace Tune-up program was offered between May 22 and September 15, 2001, and the Heating System Replacement and Insulation and Draft Proofing programs were offered between September 15 and November 30, 2001.

2.3 Program Description

BC Gas advertised the 2001 Residential DSM Campaign featuring Shell Busey in magazines, newspapers, retail stores, on radio and on their website, and through direct mail and bill inserts to customers.

The *BC Gas Furnace Tune-up program* included a $25 rebate offer for customers to have their existing forced air gas furnace tuned-up between May 22 and September 15 of 2001. BC Gas advertised the value of regular tune-ups in terms of improving energy-efficiency and safety, and encouraged customers to talk to their contractors about other energy-saving activities. Information was also provided to contractors about the program. No referrals were made to any contractor as part of the program, and contractors set their own prices for the work that was done. Qualified gas contractors were required to be registered with the *Provincial Gas Safety program*, and be licensed gas fitters. To qualify, customers returned a completed coupon and a copy of the invoice or work order to BC Gas after the contractor completed the tune-up.

The *BC Gas Heating System Replacement program* consisted of a $150 rebate for customers who replaced their heating system with a new natural gas high-efficiency heating system between September 15 and November 30, 2001. This offer was made in conjunction with manufacturer rebates, and coupons advertising these other offers were sent through direct mail to customers. To qualify for the BC Gas rebate, customers returned a completed

[23] According to BC Gas, this included a $150 BC Gas rebate off the cost of a natural gas high efficiency central heating system plus a manufacturer's rebate worth at least $150 in extended warrantees and offers.

coupon and a copy of the receipt for the new heating system to BC Gas after the contractor completed the heating system replacement.

Finally, the *BC Gas Insulation and Draft Proofing* program included a $25 rebate for customers that installed over $75 of insulation and draft-proofing home materials. Although customers could use contractors to install their materials, the rebate applied to the cost of the materials, not to labour costs for installation. To qualify for the BC Gas rebate, customers returned a completed coupon and a copy of the receipt for the upgrade materials to BC Gas.

2.4 Program Objectives

A brief discussion of the key program objectives are provided below:

To realize energy savings:
The various DSM programs were implemented to encourage BC Gas customers to either upgrade their existing heating systems to more efficient models (Heating System Replacement) and/or enhance the energy efficiency of their home either by tuning up the existing equipment (Furnace Tune-up) or installing energy saving materials in the home (Insulation and Draft Proofing).

To improve energy awareness:
The BC Gas residential DSM programs also incorporated a significant educational component, whereby contractors were asked to provide information to program participants (Furnace Tune-up, Heating System Replacement) with a variety of energy saving practices that could be used to help households reduce their energy consumption.

To transform the market-place to more efficient technologies and practices:
BC Gas worked with trade channels, manufacturers and retailers as part of the 2001 Residential DSM Campaign to support and further develop trade channel capability to delivery energy efficient products/technologies.

To assist customers in managing their energy costs:
The 2001 Residential DSM Campaign was introduced during a period of higher energy prices. As a result, the 2001 Residential DSM Campaign helped customers manage their energy costs by encouraging customers to implement energy-saving practices.

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SECTION 3: PROGRAM PARTICIPANT PROFILE

3.1 Background

Considerable demographic information was collected through the surveys of program participants. Such information would enable BC Gas to have a better understanding of the various participant populations and could be subsequently incorporated into future marketing/promotional initiatives. Key demographic characteristics examined in this report include:

- age
- income
- education
- household composition
- home ownership
- dwelling characteristics

3.2 BC Gas Program Participants – Residential Customers

The majority of respondents in all three BC Gas DSM program groups were over 45 years of age, had completed some post-secondary education, lived in single-detached dwellings and owned their own homes.

Age

Participants in the BC Gas rebate programs were not representative of the age distribution of BC as a whole, particularly for the Heating System Replacement and Furnace Tune-up programs, where the age group of 25 to 34 was underrepresented. In the case of the Furnace Tune-up program, the majority of respondents were over 65 (56%), compared to 19% in the BC population (aged 25+ years). The age distributions of respondents are detailed in Table 3-1 below.

Table 3-1
Age Distribution of Participants, Non-Participants and the BC population

Age range	Furnace Tune-up Participants	Heating System Replacement Participants	Insulation and Draft Proofing Participants	Non-participants	British Columbia population % (over age 25)*
25 to 34	2%	4%	12%	12%	21%
35 to 44	10%	21%	26%	24%	25%
45 to 54	13%	26%	20%	25%	22%
55 to 64	19%	27%	23%	16%	13%
65 and over	56%	19%	17%	20%	19%

*Statistics Canada, 2000
Note: Totals may not add to 100% due to no response

Income

Furnace Tune-up participants more commonly reported lower household earnings than both Heating System Replacement and Insulation and Draft Proofing program participants, as seen in Table 3-2 below.

Table 3-2
Household Income Distribution of Participants and Non-participants

Household Income	Furnace Tune-up Participants	Heating System Replacement Participants	Insulation and Draft Proofing Participants	Non-participants
Less than $45,000	43%	17%	20%	23%
$45,000 to less than $65,000	14%	15%	24%	18%
$65,000 to less than $100,000	12%	23%	14%	17%
$100,000 or more	8%	13%	18%	11%

Note: Totals may not add to 100% due to no response

In comparison, the average BC income in 1996 was $50,667.

Education

Most BC Gas customers surveyed had completed at least high school, and over half had completed some post-secondary education. A higher percentage of Insulation and Draft Proofing participants had obtained a university degree (38%) compared to Furnace Tune-up (31%) and Heating System Replacement (26%) participants. Table 3-3 details the educational attainment reported by participants and non-participants.

Table 3-3
Highest Level of Education Completed by Participants and Non-participants

Education	Furnace Tune-up Participants	Heating System Replacement Participants	Insulation and Draft Proofing Participants	Non-participants	BC Average (1996 Census, aged 15+ years)
Elementary school	4%	1%	0%	2%	7%
Some high school	14%	4%	6%	8%	24%
Completed high school (Dogwood certificate)	24%	25%	24%	22%	13%
Some vocational/ technical/college	4%	8%	7%	10%	7%
Completed vocational/ technical/college	17%	21%	18%	18%	20%
Some university	8%	6%	7%	11%	12%
Completed university degree	17%	20%	28%	18%	20%(1)
Post graduate degree	9%	11%	10%	7%	n/a

(1) with bachelors degree or higher. BC average also includes a wider range of regions (e.g., northern regions) that may account for some of the difference in educational profiles between BC Gas customers and the province as a whole.
Note: Totals may not add to 100% due to no response

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Household Composition
Household composition varied by rebate offer. Furnace Tune-up customers were more likely to live alone (21%) compared to both Insulation and Draft Proofing (6%) and Heating System Replacement (5%) participants. Furnace Tune-up customers were also less likely to have children present in the household (16%), compared to 31% of both Heating System Replacement and Insulation and Draft Proofing participants, and 43% of Non-participants, as well as compared to the BC population (43%).

Home Ownership
The vast majority of all BC Gas customers reported owning their homes:

- Furnace Tune-up (99%)
- Heating System replacement (98%)
- Insulation and Draft Proofing (98%)
- Non-participant (90%)

Slightly more non-participants reported renting than participants in all three rebate programs. These numbers are not representative of the BC population as a whole, where only two thirds of the population own their homes.

Age, Size and Type of Dwelling
Participants in both the Heating System Replacement and Insulation and Draft Proofing programs were more likely to have older homes than those in the Furnace Tune-up program as indicated in Table 3-4. As detailed in the Table, residential DSM customers generally resided in older homes (i.e., more than 25 years old) as compared to non-participants and/or the BC average.

Table 3-4
Age of Home (Participants and Non-participants)

Age of home	Furnace Tune-up Participants	Heating System Replacement Participants	Insulation and Draft Proofing Participants	Non-participants	BC Average (1996 Census)
1 to 25 years	50%	33%	32%	47%	61%
26 to 50 years	35%	46%	47%	33%	29%
Over 50 years	11%	14%	17%	12%	10%

Note: Totals may not add to 100% due to no response

Participants in the Furnace Tune-up program were less likely to have homes over 2500 square feet (14%) than both Heating System Replacement (24%) and Insulation and Draft Proofing (24%) respondents[24]. Again, this likely reflects the older age group of Furnace Tune-up participants.

Table 3-5
Size of Home of Participants and Non-participants

Size of home	Furnace Tune-up Participants	Heating System Replacement Participants	Insulation and Draft Proofing Participants	Non-participants
Under 1500 sq feet	30%	30%	26%	30%
1500 to 2500 sq feet	37%	39%	46%	36%
Over 2500 sq feet	14%	24%	24%	23%

Note: Totals may not add to 100% due to no response

Most respondents lived in single-detached homes, as shown in Table 3-6 below.

Table 3-6
Type of Dwelling of Participants and Non-participants

Type of Dwelling	Furnace Tune-up Participants	Heating System Replacement Participants	Insulation and Draft Proofing Participants	Non-participants
Single-detached	76%	94%	89%	82%
Semi-detached	4%	2%	3%	4%
Apartment / condominium	2%	0%	2%	2%
Row / Townhouse	9%	1%	2%	7%
Mobile home	8%	2%	2%	4%

Note: Totals may not add to 100% due to no response

3.3 Program Participant Demographics – Key Issues

Analysis of program participant profile yields several interesting observations regarding the various DSM programs, including:

- **Programs attracted significantly different populations**
  The participants of the various DSM programs were not homogeneous. As noted previously, whereas the majority of Furnace Tune-up participants were 65 years of age or older, only 19% of Heating System Replacement participants were 65 years of age or older. Similarly, there were marked differences in the income and educational profile of the three participant groups, with Insulation and Draft Proofing participants reporting higher income and education compared to Furnace Tune-up and Heating System Replacement participants.

[24] This finding was true even when "don't know" responses were removed from the analysis.

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- **Program participants tended to own older homes**
  Relative to the 39% of homes in BC that were more than 25 years old, a much higher proportion of participants noted that their home was built more than 25 years ago (Tune-up: 46%, Insulation/draft proofing: 64%, and Heating System Replacement: 60%).
- **Literacy/comprehension may be issue for some program participants**
  The design of marketing/communication strategies should recognize the considerable range in education of participants in the various DSM programs. For example, almost one in five (18%) of Furnace Tune-up participants noted that they did not have a high school diploma. In contrast, only 5% of Heating System Replacement participants indicated that they did not have a high school diploma.

Survey participants were asked to comment on their satisfaction with BC Gas' communication and promotion of the Furnace Tune-up, Heating System Replacement, and Insulation and Draft Proofing rebate programs. Also examined in the process review were participant and non-participant assessments of the financial incentives offered as part of the BC Gas 2001 Residential DSM Campaign.

4.1 Program Administration

When asked how easy they found participating in the BC Gas rebate programs, most participants reported finding participation easy or very easy. Most participants also reported being satisfied with the information provided to them by their heating contractor. The most common energy saving information provided concerned air filter cleaning and replacement schedules.

4.1.1 Ease of Program Participation

Participants in the Furnace Tune-up, Insulation and Draft Proofing and Heating System Replacement programs were all likely to report that program participation was easy or very easy (96%, 92% and 89% of participants respectively).

Table 4-1
Ease of participation in BC Gas Programs

	Participants			**Contractors / Manufacturers**		
	Furnace Tune-up participants	Heating System Replacement participants	Insulation and Draft Proofing participants	Furnace Tune-up contractors	Heating System Replacement contractors	Heating System Replacement manufacturers / distributors
Very Easy	78%	70%	66%	60%	64%	36%
Easy	18%	19%	26%	22%	25%	27%
Neutral	3%	7%	7%	10%	6%	18%
Difficult	1%	3%	1%	2%	6%	9%
Very Difficult	0%	2%	0%	4%	0%	9%
% Easy/ Very Easy	96%	89%	92%	82%	89%	63%

A majority of contractors also indicated that program participation was easy or very easy (Furnace Tune-up contractors: 82%, Heating System Replacement contractors: 89%). Table 4-1 provides a distribution of responses to a question concerning ease of participation for each of the participant, contractor and manufacturer groups.

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When contractors were asked whether they had any comments[25] about the ease of participation in the Heating System Replacement program, the largest group of contractors reiterated that the program was easy to participate. Only a small number of contractors suggested changes to the program to improve ease of participation; three contractors suggested that more notice should have been given about the program (8%).

Contractors in the Heating System Replacement program were also asked to rate the ease or difficulty of participation in the manufacturers' offers or rebates. In response to this question, half of contractors (50%) reported that it was easy or very easy for them to participate in the manufacturers' offers or rebates[26]. When asked to comment on the ease of participation in the manufacturer programs, contractors were most likely to state that manufacturers did not communicate their rebate offer well (11%[27]) or that program participation was easy (8%[28]).

It is interesting to note that Heating System manufacturers/distributors were less positive about the ease of participation in the program (63%) than were actual program participants (89%). When asked to comment on the ease of participation, manufacturers commonly mentioned that more notice or a longer program would have been helpful[29]. In addition, two of the eleven manufacturers surveyed indicated that paper work required for the program was difficult to complete or unclear.

[25] Open-ended question which asked contractors whether they had comments about the ease or difficulty of participation in the program.
[26] This result compares to 89% of contractors who felt that participation in the BC Gas Heating System Replacement program was easy.
[27] Represents 4 contractors.
[28] Represents 3 contractors.
[29] This comment was made by 3 out of 11 manufacturers. Please note that the manufacturer/distributor sample size is too small for extensive analysis/comparisons.

4.1.2 Information provided to Customers by Contractors

In general, both participants and contractors reported a high frequency with which contractors provided information about air filter cleaning and replacement, temperature setback savings and high-efficiency furnaces. As indicated in Table 4-2, energy-saving items most commonly explained to participants in both the Furnace Tune-up program (75%) and the Heating System Replacement program (80%) included air filter cleaning and replacement schedules.

Table 4-2
Information Provided to Customers

	Furnace Tune-up Program		Heating System Replacement Program	
	Participants	Contractors	Participants	Contractors
Air Filter Cleaning and Replacement Schedule	75%	84%	80%	95%
Temperature Setback Savings	66%	72%	68%	89%
Benefits of High Efficiency Furnaces	52%	58%	n/a	95%

In addition, nearly all contractors reported explaining the benefits of high efficiency furnaces to all or most of their Heating System Replacement customers (95%).

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4.2 Communications Issues

4.2.1 Advertising and Marketing

DSM participants reported most commonly being made aware of the BC Gas rebate programs through inserts in their BC Gas bills. Table 4-3 lists marketing or advertising activities most commonly identified by customers and contractors / manufacturers as a source of awareness about the program.

Table 4-3
Sources of Awareness about Programs

	Participants			Contractors / Manufacturers		
	Furnace Tune-up participants	Heating System Replacement participants	Insulation and Draft Proofing participants	Furnace Tune-up contractors	Heating System Replacement contractors	Heating System Replacement manufacturers / distributors
Top 3 Sources of Awareness about Program	BC Gas bill insert (34%) Newspaper insert (14%) Advertisement in Mail (14%)	BC Gas bill insert (29%) Heating Contractor Information (24%) Advertisement in Mail (13%)	BC Gas bill insert (28%) Store ad (15%) Newspaper insert (12%)	BC Gas bill insert (56%) Newspaper insert (38%) Radio ad (36%)	Advertisement in Mail (44%) BC Gas bill insert (39%) Newspaper insert (36%)	BC Gas bill insert (73%) Radio ads (27%) Magazine ad (18%)

Contractors, manufacturers, and participants were also asked to suggest ways to improve advertising of the DSM programs. In response, the largest group of contractors indicated that BC Gas' advertising was fine (18%). The most common contractor suggestions to better market or advertise the Furnace Tune-up program were to:

- Increase television ads (10%);
- Increase radio ads (10%); and
- Include advertisements with the gas bill (10%)[30].

When asked for suggestions for BC Gas to better market or advertise the Heating System Replacement program, contractors suggested that BC Gas could also have put advertisements in with the gas bill (11%), increase newspaper ads (6%), or advertise earlier (3%). Manufacturers surveyed as part of the Heating System Replacement program indicated that BC Gas could have provided more TV or radio advertising[31] in order to better market the program. These results suggest that a multi-channel approach including inserts and radio / TV advertisement should be continued or enhanced for future campaigns.

[30] It should be noted that BC Gas did advertise the 2001 Residential DSM Campaign through bill inserts, newspapers, magazines, retail stores, radio, and the BC Gas website. It might be possible to increase general awareness of bill inserts by providing increased notice about DSM programs prior to commencement of the program or by advertising upcoming bill inserts.

[31] 3 and 2 manufacturers respectively.

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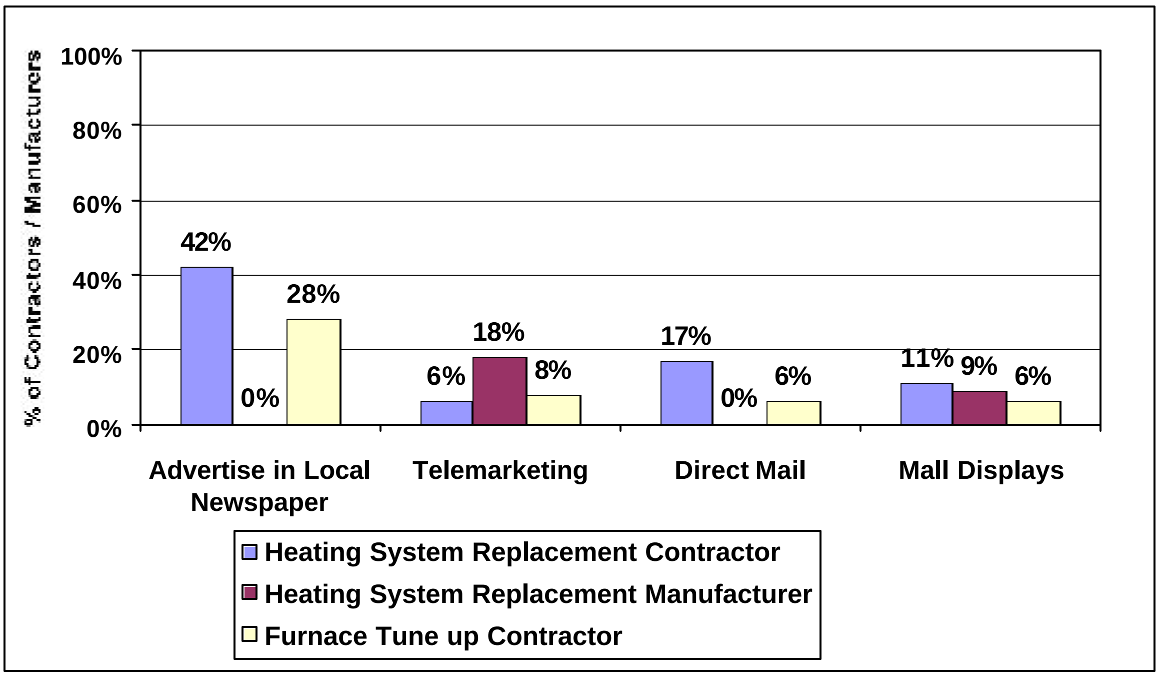
When asked whether their firm had engaged in marketing or advertising activities to solicit business, 32% of Furnace Tune-up contractors and 47% of Heating System Replacement contractors had engaged in some form of marketing/advertising activity to solicit business. The most common type of advertising activities among Furnace Tune-up (28%) and Heating System Replacement (42%) contractors was advertisement in local newspapers. Among manufacturers, telemarketing activities were reported (18%), as indicated in Chart 4-1. Nearly half of manufacturers reported engaging in other advertising activities (46%)[32].

Chart 4-1
Marketing Efforts by Contractors



4.2.2 Awareness of BC Gas Rebate Programs

Less than one-half of Furnace Tune-up contractors (46%) and Heating System Replacement contractors (40%) agreed that customers were aware of those respective rebate programs before making an inquiry with their firm. Contractors also indicated that, on average, 14% of customers that participated in the Furnace Tune-up program, and 32% of customers that participated in the Heating System Replacement program were unaware of the program before being informed by the contractor.

With respect to manufacturer offers, most contractors (83%) reported that they were aware of additional manufacturers' offers or rebates available to customers, and almost two-thirds (61%) of Heating System Replacement participants were aware of the manufacturer offers.

[32] Other advertising activities included brand incentive programs, partner referral and flyers, advertising in trade magazines, and home show displays.

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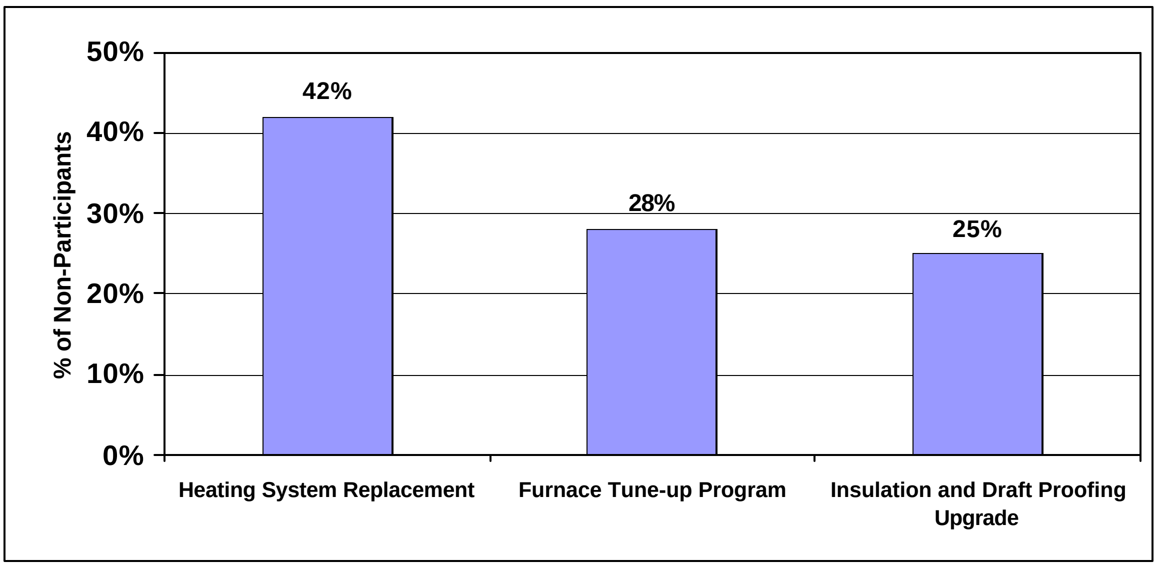
Across programs, almost three-quarters of Insulation and Draft Proofing participants (73%) were also aware of the $150 Heating System Replacement program, though only 3% also participated in the offer. In comparison, notably fewer Heating System Replacement participants (41%) were aware of the BC Gas $25 Insulation and Draft Proofing program.

Non-Participants

As highlighted in Chart 4-2, in general, there was a low level of awareness of the three residential DSM programs among non-participants. Specifically, while 42% of non-participants indicated that they were aware of the Heating System Replacement program, there was markedly less awareness of the Furnace Tune-up program (28%) or Insulation and Draft-Proofing (25%) program among this group.

Chart 4-2
Awareness of Rebate Programs among Non-Participants



Non-participants who noted that they were aware of the Furnace Tune-up, Heating System Replacement, and Insulation and Draft Proofing programs, most commonly reported being made aware of these programs from BC Gas bill inserts (15%, 21%, and 14%, respectively), followed by inserts in the local newspaper (2%, 5%, and 2% respectively).

4.3 Assessment of Financial Incentives

Most participants in the Furnace Tune-up program reported that the financial incentive provided was adequate (76%). In contrast, less than half of participants in the Heating System and Insulation and Draft Proofing programs indicated that the financial incentive provided was adequate. The average proposed rebates among those participants that reported that the incentive was not adequate was $377[33] for the Heating System and $113 for the Insulation and Draft Proofing participants[34]. Table 4-4 provides information about customer assessments of the financial incentives provided by BC Gas.

Table 4-4
Assessment of Financial Incentives for BC Gas Rebate programs

	Participants			Contractors / Manufacturers		
	Furnace Tune-up participants	Heating System Replacement participants	Insulation and Draft Proofing participants	Furnace Tune-up contractors	Heating System Replacement contractors	Heating System Replacement manufacturers / distributors
Was incentive adequate? (yes)	76%	41%	39%	80%	75%	60%
Average proposed incentive*	$64	$377	$113	$74	$383	$300[35]
Rebate important/very important	45%	38%	36%	66%	55%	36%
Rebate unimportant/ not at all important	25%	32%	34%	10%	17%	0%

* Among those indicating rebate was not adequate[36].
Note: % does not add to 100% due to neutral responses not reported.

Consistent with the participant results, two-thirds of non-participants felt that a $25 Furnace Tune-up rebate would be an adequate incentive. Of those non-participants that felt that this incentive would be inadequate, the average rebate proposed was $79. Of the two-thirds of non-participants (69%) that described a $150 rebate as inadequate for the Heating System Replacement program, the average proposed rebate was $547. Of note, the proposed rebate by non-participants was higher than that proposed by Heating System program participants who felt that the rebate was inadequate[37].

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33 Top two scores removed from the analysis.
34 In comparison, (51%) of Heating System Replacement program participants felt the manufacturers' rebate provided an adequate incentive. The mean proposed rebate among participants who felt that the manufacturers' rebate was not an adequate incentive was $550.
35 One manufacturer
36 Sample sizes for this question are as follows: Furnace Tune-up participants, 67; Heating System Replacement participants, 85; Insulation and Draft Proofing participants, 64; Furnace Tune-up contractors, 10; Heating System Replacement contractors, 9; Heating System Replacement manufacturers/distributors, 1.
37 Non-participants likely would have less information on which to estimate an adequate incentive, as non-participants would have been less likely to have investigated the cost of a heating system replacement.

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4.3.1 Total Cost of Energy Saving Activity

The average cost of a Furnace Tune-up was $88[38], of which an average of $75 was for labour. On average, participants paid $63 after the rebate for their Furnace Tune-up. With respect to the Heating System Replacement rebate program, the mean total cost of the Heating System Replacement was $3332[39]. The average cost of the insulation and draft proofing materials reported by participants in the Insulation and Draft Proofing program was $538, with the top two scores removed from the analysis[40].

As highlighted in Table 4-5, whereas the $25 Furnace Tune-up rebate provided by BC Gas covered approximately 28% of the total cost of the furnace tune-up, the proportion of the total cost of the heating system replacement and/or insulation and draft proofing rebate provided by BC Gas was only 5% of the total expenditure as reported by program participants.

Table 4-5
BC Gas Rebate as a Percentage of Total Cost

	Furnace Tune-up	Heating System Replacement	Insulation and Draft Proofing
BC Gas Rebate	$25.00	$150.00	$25.00
Average Total Expenditure	$88.00	$3,332.00	$538.00
BC Gas Rebate as % of total expenditure	28%	5%	5%

4.4 Program Delivery – Key Issues

- **While a majority of participants, contractors, and manufacturers found program participation easy, satisfaction was somewhat lower among contractors and manufacturers.**

  While participants describing program participation as easy ranged between 89% for Heating System Replacement participants and 96% for Furnace Tune-up program participants, a lower proportion of manufacturers and distributors reported that program participation was easy (63%). Providing more notice, running a longer program, or simplifying required paperwork may help to increase ease of participation for manufacturers[41].

[38] The top 2 scores were removed from this analysis.
[39] The top 2 scores were removed from this analysis.
[40] Participants in the Insulation and Draft Proofing program were most likely to install insulation (79%), new weather stripping (28%), or caulking of exterior windows (21%) and doors (12%), and 60% of participants installed the materials themselves (28% of Insulation and Draft Proofing program participants had the materials installed by a contractor.).
[41] Based on manufacturer suggestions regarding ease of program participation.

- **BC Gas bill inserts were most effective in making BC Gas customers aware of the 2001 Residential DSM Campaign.**

  Nearly one-third of participants and between 14% and 21% of non-participants reported being made aware of the BC Gas programs through bill inserts. Contractor awareness of BC Gas' advertising efforts varied, with Heating System Replacement contractors reporting lower levels of awareness of BC Gas marketing efforts such as bill inserts.

- **Of the three programs, non-participants reported highest awareness of the Heating System Replacement program.**

  Over 40% of non-participants were aware of the Heating System Replacement program, compared to 28% and 25% that were aware of the Furnace Tune-up and Insulation and Draft Proofing programs.

- **While most Furnace Tune-up program participants reported that the rebate offered by BC Gas was adequate, a minority of participants in the Heating System and Insulation and Draft Proofing programs felt BC Gas program incentives were adequate.**

  Heating System Replacement participants recommended an average rebate of $377[42] (or 11% of the average cost of a furnace replacement reported by respondents). Insulation and Draft Proofing program participants recommended a rebate of $113, or approximately 21% of the average cost of insulation and draft proofing materials purchased by respondents. It should be noted that 25% of all Insulation and Draft Proofing participants indicated that the size of the rebate should be a percentage of the cost of materials.

[42] Top two scores removed from the analysis.

SECTION 5: GENERAL SATISFACTION WITH THE PROGRAM

Respondents were asked to summarize their satisfaction with the BC Gas rebate programs and were also asked to identify what improvements, if any, they could suggest to make them more effective.

5.1 General Satisfaction with the BC Gas 2001 Residential DSM Programs

5.1.1 Overall Satisfaction with BC Gas Rebate Programs

Overall, participants in all programs reported very high levels of satisfaction with the BC Gas rebate programs. Specifically, 90% of Furnace Tune-up, 87% of Heating System Replacement, and 78% of Insulation and Draft Proofing participants reported being "very satisfied" or "satisfied" with the program.

Table 5-1
Participant and Contractor/Manufacturer
Satisfaction with the BC Gas Rebate programs

	Participants			Contractors / Manufacturers		
	Furnace Tune-up participants	Heating System Replacement participants	Insulation and Draft Proofing participants	Furnace Tune-up contractors	Heating System Replacement contractors	Heating System Replacement manufacturers / distributors
Very satisfied	69%	57%	50%	48%	39%	55%
Satisfied	21%	30%	28%	26%	50%	27%
Neutral	6%	7%	17%	24%	11%	18%
Dissatisfied	1%	0%	1%	0%	0%	0%
Very dissatisfied	0%	1%	1%	0%	0%	0%
% satisfied/ very satisfied	90%	87%	78%	74%	89%	82%

When asked why they were satisfied with the program, the most common theme that emerged among Furnace Tune-up participants was that the rebate had helped them to save money, both with respect to the $25 as well as on future energy costs (51%). Fourteen percent of respondents mentioned they were satisfied because the rebate had provided an incentive for them to complete the tune-up, and 16% of participants were satisfied because program participation was simple. Some responses included:

> *"I am satisfied with anything that will reduce the cost of gas. The bills have been going up so much."*

> *"It was straightforward and it gave me an incentive to get the servicing done early, rather than putting pressure on the technician later on in the season."*

Only 23 respondents did not indicate that they were satisfied with the program[43]. Overall, the most common reasons for this included that the rebate work was too slow in being processed, or that they were dissatisfied with the work of the contractor.

Among Heating System Replacement participants, the most common reason for program satisfaction was that the rebate saved money on the purchase price of a heating system (30%[44]). Respondents also stated that program participation was simple (20%) and that the rebate was timely (14%). Some comments included:

> *"I was satisfied with the rebate offer because it was free. It was really easy to send the coupon in and it took away from the installation cost of my new furnace."*

> *"The information they needed was straightforward and easy to obtain and it's always nice to get a refund."*

> *"As soon as it went through their system, I got the rebate on my next bill."*

The most common reason given for participants' lack of satisfaction was that the rebate was slow in coming (4%). A small number of respondents also stated that the rebate was too small (1%), or that the offer was too complicated and required too much paperwork (1%). A selection of the respondents' comments is below:

> *"They should give the rebate back sooner because for me it took over four and half months until it showed up on my bill."*

> *"I was satisfied with the offer, but had to jump through hoops to get it. I bought my furnace wholesale and installed it myself. They wanted a receipt from a gas contractor. At the time, I had not started my own business. I had to write a couple of letters before I got the rebate."*

Finally, among Insulation and Draft Proofing participants the most common reason for program satisfaction was that the rebate saved money (33%[45]). A further 25% noted the ease of program participation, and 12% stated that the offer provided an incentive to upgrade their insulation and draft proofing. Some comments included:

> *"It really encourages people to seal their houses and to save money."*

> *"The rebate was clear, and applicable to the cost of the service. It encourages people to do the right thing."*

Insulation and Draft Proofing participants that did not report being satisfied with the offer were most likely to state that the rebate was an insufficient amount, the rebate was slow in coming, and that the rebate guidelines were unclear. A selection of comments is below.

> *"It took them a really long time to process it. Considering the amount you have to pay to draft proof and insulate your house, the amount is really negligible."*

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[43] Included 19 respondents describing themselves as neutral.
[44] Of all Heating System Replacement participants.
[45] Of all Insulation and Draft Proofing participants

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> *"I spent two hundred dollars; others spent $75 and get $25! It should have been done in increments. And when I called in, nobody knew where to transfer me. There was no website to access."*

Contractors reported high levels of satisfaction with the Furnace Tune-up and Heating System Replacement programs, with 74% of contractors indicating that they were satisfied with the Furnace Tune-up program, and 89% indicating satisfaction with the Heating System Replacement program. Eighty-three percent of manufacturers/distributors were also satisfied with the Heating System Replacement program.

When asked whether they would be willing to participate in future energy saving programs offered by BC Gas, 96% of Furnace Tune-up contractors indicated willingness to participate. When Heating System Replacement contractors were asked the same question, 97% indicated they would be willing to participate[46].

5.1.2 Satisfaction with Heating Contractor Information (Education Activities)

The majority of participants in both the Furnace Tune-up and the Heating System Replacement rebate offers were satisfied with the energy-saving information provided by their contractor. The most common reason given for satisfaction was that the information was thorough and easy to understand.

Furnace Tune-up

Over two-thirds (71%) of Furnace Tune-up program participants were satisfied (26%) or very satisfied (45%) with the energy-saving information provided by their heating contractor[47]. When asked why they were or were not satisfied with the energy-saving information provided to them by their heating contractor, the greatest number of respondents indicated that the explanation was thorough and easy to understand (29%), and 18% of participants indicated that the contractor suggested energy-saving ideas. Overall, the most common reasons for participant dissatisfaction with contractor information were that the contractor didn't provide sufficient or clear information (6%), or that the contractor tried to sell the participant products that they felt they didn't need (2%).

Heating System Replacement

Over three-quarters of participants said they were satisfied or very satisfied with the energy saving information provided to them by their contractor[48]. The most commonly reported reason participants gave when asked why they were satisfied with the information from their contractor was that the explanation was thorough and easy to understand (38%).

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[46] In comparison 87% of Furnace Tune-up, 77% of Heating System Replacement, and 88% of Insulation and Draft Proofing participants reported that they were willing to participate in future energy-saving programs.

[47] Reflects percentage of all Furnace Tune-up participants.

[48] In addition to satisfaction with information provided by contractors, participants also reported being satisfied with contractor services. Specifically, over three-quarters of Heating System Replacement participants (81%) did not experience any problems with the installation of their new natural gas high-efficiency furnace. Approximately 9% experienced dissatisfaction with their contractor/contractor errors.

A selection of comments regarding satisfaction with contractor's provision of energy-saving information is provided below:

> *"It was thorough and had comparisons right in it as to what you were paying and what you would be paying with the energy efficient furnace."*

> *"Our contractor sat down with us and explained all of our options as well as ways to save money in the future with the air filter schedule and by turning down/off of the heat."*

The most common reason why participants were dissatisfied with the information their contractor provided was that it was inadequate (8%). Some comments included:

> *"There was not much that he said that wasn't common knowledge. He basically just did the work and had no literature to back anything up that he said."*

> *"The information about how to save energy was included in the brochure but the contractor didn't take the time to explain it personally after the installation."*

5.2 Suggested Improvements Cited by Contractors

When contractors were asked to suggest any changes to improve or enhance the Furnace Tune-up program, the most common suggestions concerned changing the timing of the program (10%)[49] and raising the rebate amount (10%). Eight percent of contractors suggested that BC Gas should consider eliminating the quota on participants or making the program on-going. Furnace Tune-up contractors were also asked to provide suggestions for future energy saving programs that BC Gas could offer. The most commonly mentioned suggestion was to offer a rebate for furnace replacement (18%). In addition, 4% of contractors mentioned an educational campaign.

Among Heating System Replacement contractors, the most commonly mentioned suggestion involved increasing the rebate amount (17%) and offering the rebate for a longer period of time (11%). Suggestions for other programs included offering rebates for a range of different products (14%) such as high efficiency hot water tanks or commercial equipment.

[49] Although there was little agreement from these contractors as to whether the program should be scheduled in the fall (later) or in the spring (earlier).

5.3 Program Satisfaction – Key Issues

- **Participants, contractors and manufacturers/distributors consistently reported high levels of satisfaction with the BC Gas 2001 Residential DSM Campaign.**

  Specifically, 90% of Furnace Tune-up, 88% of Heating System Replacement, and 78% of Insulation and Draft Proofing program participants reported being satisfied or very satisfied. In addition, 74% of Furnace Tune-up contractors, 89% of Heating System Replacement contractors, and 82% of manufacturers and distributors were satisfied with the program.

- **Participants were most likely to be satisfied with the program because the rebate saved them money.**

  The most common reason for satisfaction among program participants was that the rebate helped them save money. Only a small number of participants reported that they were dissatisfied with the program. However, issues causing dissatisfaction included the speed with which the rebate was processed, the size of the incentive, or a perception that the rebate guidelines were unclear, rather than a general dissatisfaction with the goal of the program.

- **Contractors were most likely to suggest increasing the rebate amount and offering the program for a longer period of time.**

  Suggestions made by contractors reflected enhancements to the program, rather than substantial modifications, in light of the high levels of satisfaction among this group. Specifically, contractors in the Furnace Tune-up program suggested changing the timing of the program, raising the rebate amount, and eliminating the quota on participants or making the program on-going. Heating System Replacement contractors were most likely to suggest increasing the rebate amount, and offering the rebate for a longer period of time.

6.1 Market Impact of the BC Gas Rebate Programs

Market impact was highest for the Furnace Tune-up program. Specifically, based on approximately 27,324[50] Furnace Tune-up program participants, the participation rate of this program is 4.2%[51]. The participation rate for the Heating System Replacement program (1,423 participants) was 0.2%, and was 0.2% for the Insulation and Draft Proofing program (1,607 participants) as well.

6.2 Importance of Rebate in Prompting Maintenance Activity

The largest group of participants indicated that the rebate was important in encouraging participants to complete the maintenance activity. Specifically, 45% of participants in the Furnace Tune-up program, 38% of participants in the Heating System Replacement program, and 36% of participants in the Insulation and Draft Proofing program described the rebate as important or very important. As indicated in Table 6-1, contractors were more likely to state that the rebate was important in prompting their customers to complete the maintenance activity[52].

Table 6-1
Importance of Rebate in Prompting Maintenance Activity by Program

	Participants			Contractors / Manufacturers		
	Furnace tune-up participants	Heating System Replacement participants	Insulation and Draft Proofing participants	Furnace Tune-up contractors	Heating System Replacement contractors	Heating System Replacement manufacturers / distributors
Rebate important/very important	45%	38%	36%	66%	55%	36%
Rebate unimportant/ not at all important	25%	32%	34%	10%	17%	0%

* Among those indicating rebate was not adequate.
Note: Totals will not add up to 100% due to neutral responses not shown.

Comparing the manufacturer and BC Gas Heating System Replacement program rebates, approximately one quarter (27%) of Heating System Replacement participants said that the

[50] Reflects approved participants.
[51] Based on 657,120 BC Gas customers in the Interior and Lower Mainland. Total number of customers in Lower Mainland is 450,289 and total number of customers in the Interior is 206,831. Data provided by BC Gas.
[52] Directional only.

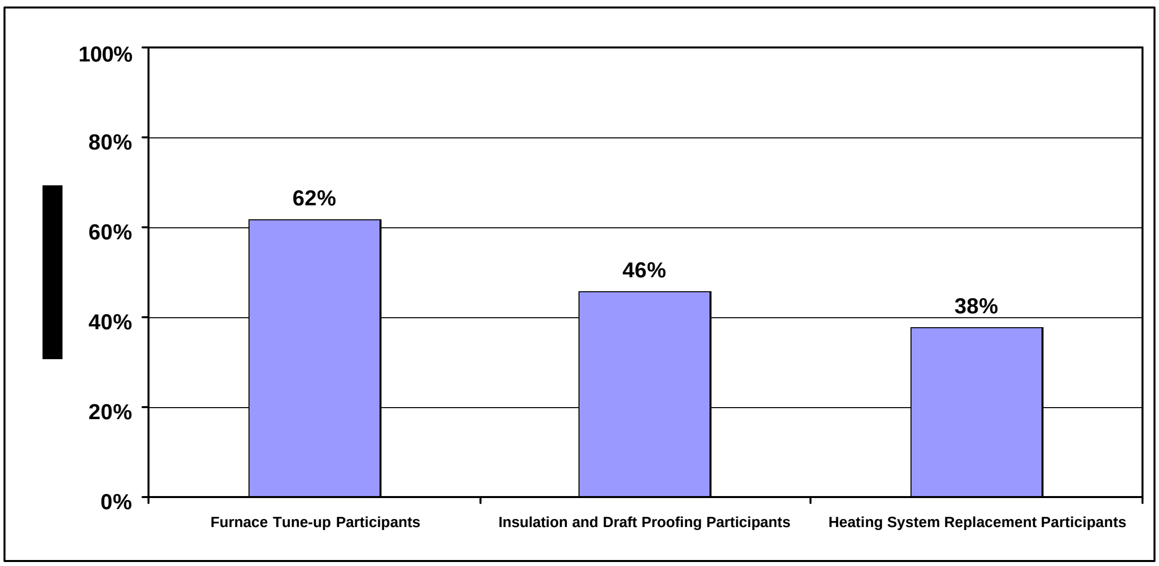
BC Gas rebate was the most important rebate, followed by 17% reporting that both were of the same importance[53].

[53] Only 9% of participants indicated that the manufacturer rebate was the most important rebate (16 respondents). It must be noted, however, that only 11 manufacturers/distributors were surveyed.

6.2.1 Impact of Incentive in Prompting Early Maintenance

Participants in the BC Gas 2001 Residential DSM Campaign were also asked about the impact of the rebate programs in encouraging them to complete maintenance or heating system replacement activities earlier than they would have without the rebate. Chart 6-1 illustrates the percentage of Furnace Tune-up, Heating System Replacement and Draft Proofing and Insulation program participants reporting that they completed maintenance/replacement activities earlier as a result of the rebate programs.

Chart 6-1
Participants Reporting that Rebate Encouraged Early Maintenance/Heating System Replacement



As indicated in Chart 6-1, two-thirds of Furnace Tune-up respondents (62%) felt the rebate program encouraged them to get maintenance earlier than they would have done otherwise. Forty-six percent of Insulation and Draft Proofing participants and 38% of Heating System Replacement participants stated that the rebate program encouraged early completion of the maintenance or replacement.

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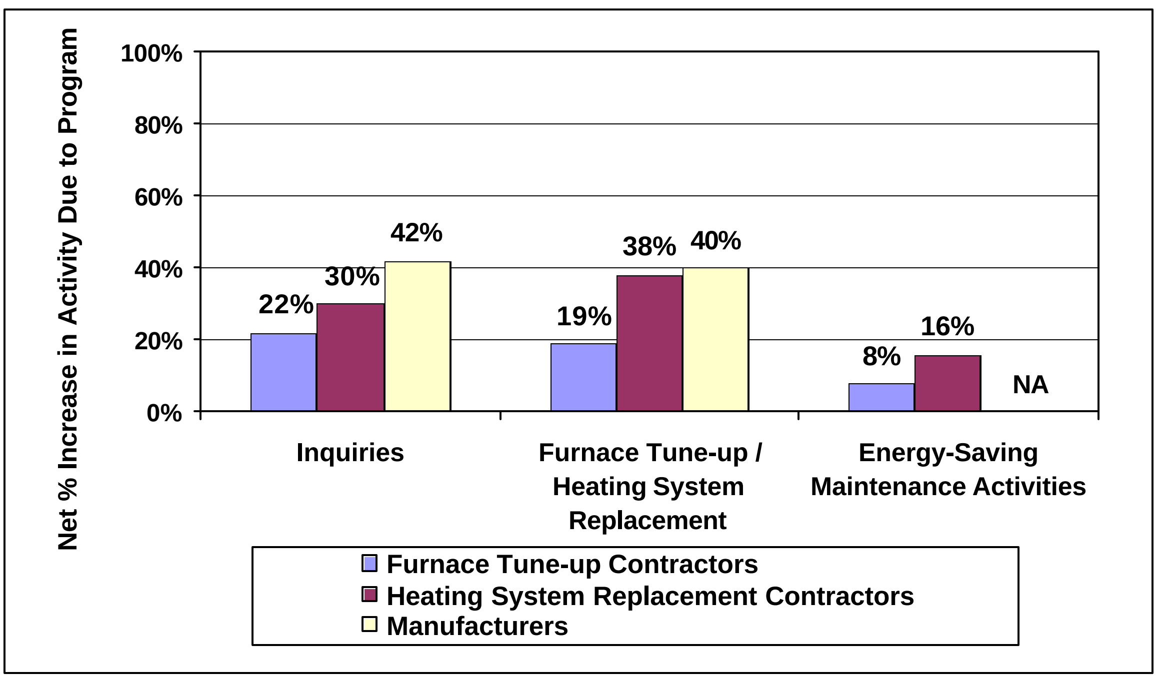
6.3 Program Impact on Contractors, Manufacturers and Distributors

The BC Gas 2001 Residential DSM Campaign did appear to have a significant impact on the number of inquiries, heating system replacement / tune-up and other maintenance activities completed by contractors. In total, contractors in the Furnace Tune-up program reported a greater number of inquiries (56% of contractors), furnace tune-ups (56%), and energy-saving maintenance activities (30%) as a result of the program. In addition, contractors in the Heating System Replacement program reported increases in the number of inquiries (67% of contractors reported increases), heating system replacements (72%), and energy-saving maintenance activities (44%) as a result of the program.

As indicated in Chart 6-2, contractors for both the Furnace Tune-up and Heating System Replacement programs reported significant increases in contract work due to the BC Gas 2001 Residential DSM Campaign. Specifically, contractors in the Furnace Tune-up program reported an average increase of 22% in the number of inquiries about furnace tune-ups due to the program[54], a 19% increase in furnace tune-up business[55], and an 8% increase in energy-saving maintenance or insulation activities[56].

Chart 6-2
Net Change in Contractor Activity Due to BC Gas DSM Campaign



[54] $t = 5.4$, $p < .05$.
[55] $t = 4.1$, $p < .05$.
[56] $t = 2.2$, $p < .05$.

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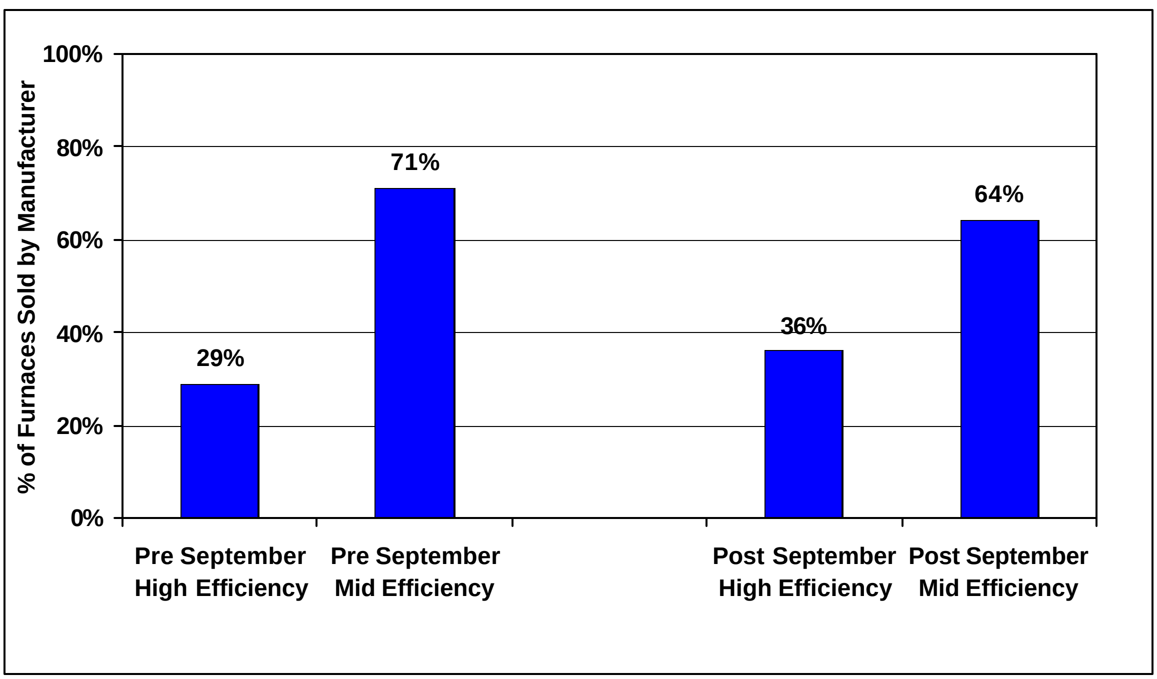
Similarly, contractors in the Heating System Replacement program reported a 30% increase in the number of inquiries on average[57], a 38% increase in the number of heating system replacements[58], and a 16% increase in the number of energy-saving maintenance activities[59] completed as a result of the Heating System Replacement program.

Manufacturers and distributors also reported an increase in business due to the Heating System Replacement program. Two-thirds of manufacturers (64%) reported that as a result of the rebate programs offered by their company and BC Gas they had sold more natural gas high-efficiency central heating systems and 82% reported more inquiries[60]. A majority of manufacturers felt that higher energy costs (82%), the availability of the manufacturer rebate (73%), the BC Gas rebate (64%) and product advertising (64%) contributed to this increased consumer interest. In comparison, only 27% of manufacturers reported that changes in energy prices over the past two years had resulted in an increase in the number of heating systems sold.

It appears that the Heating System Replacement program had an impact on the percentage of high efficiency heating systems sold by manufacturers/distributors. As Chart 6-3 indicates, the percentage of high efficiency heating systems changed from 29% before September 15, 2001 to 36% after September 15, 2001.

Chart 6-3
Change in Manufacturer/Distributor Sales of High and Mid Efficiency Furnaces Due to BC Gas DSM Campaign



[57] $t = 3.2$, $p < .05$.
[58] $t = 3.3$, $p < .05$.
[59] $t = 3.2$, $p < .05$.
[60] Net increase of 40% in number of natural gas high efficiency central heating systems sold and increase of 42% in number of inquiries, as illustrated in Chart 6-2.

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In total, manufacturers reported having processed 186 applications for their offer or rebate since September 15th (4 manufacturers)[61].

6.4 Program Impact – Key Issues

- **The Furnace Tune-up program attracted over 15 times as many participants as the Heating System Replacement and Insulation and Draft Proofing programs.** Based on 27,324 Furnace Tune-up participants, the market impact for this program was 4.2%, compared to 0.2% for the Heating System Replacement program (1,423 participants) and the Insulation and Draft Proofing program (1,607 participants).

- **Program participants reported that the BC Gas DSM programs were important in encouraging maintenance activity.** The number of participants reporting the DSM programs were important in encouraging the maintenance activity ranged from 45% for Furnace Tune-up participants to 36% of Insulation and Draft Proofing participants. In addition, 62% of Furnace Tune-up participants, 46% of Insulation and Draft Proofing participants and 38% of Heating System Replacement participants reported that the rebated caused them to complete the maintenance earlier than they would have otherwise.

- **The BC Gas 2001 Residential DSM Campaign resulted in significant increases in inquiries, heating system replacements / tune-ups, and other maintenance work reported by contractors.** Contractors reported twenty to thirty percent increases in the number of inquiries, and 8% to 16% increases in other maintenance work resulting from the DSM Campaign. Contractors in the Furnace Tune-up program reported 19% more furnace tune-up business as a result of the program, and contractors in the Heating System Replacement program reported a 38% increase in the number of heating system replacements completed.

- **Manufacturers also reported a greater number of inquiries and sales of natural gas high efficiency furnaces.** Two-thirds of manufacturers reported selling more natural gas high efficiency heating systems as a result of the program. In addition, manufacturers reported that the percentage of high efficiency heating systems (compared to mid efficiency systems) sold increased from 29% before September 2001 to 36% after September 2001.

[61] 82% of manufacturers surveyed had provided a special offer or rebate available to customers purchasing a natural gas high-efficiency heating system.

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SECTION 7: ESTIMATING THE NET IMPACT OF THE RESIDENTIAL DSM PROGRAMS: ADMINISTRATIVE DATA ANALYSIS

7.1 Background

While surveys are commonly used to assess the impact/importance of residential DSM programs, this approach ignores the cumulative impact of the range of activities (i.e., energy awareness, changes in behavior) that could be completed to reduce energy consumption. In addition, during a period of rising energy prices, it would be natural to assume that a significant proportion of non-participating households would also implement energy-saving technologies/practices in the absence of any program(s).

Use of administrative data on a pre/post program basis, comparing aggregate energy consumption for participant households relative to that of a representative sample of comparison households can be used to identify the net impact of DSM programs. Through such an approach (i.e., use of comparison households), it is not necessary to adjust for weather and/or pricing changes, as these impacts should have an equal impact on both participant and non-participant households.

7.2 Sample Frame Construction

In order to identify the net impact of the program on participating households, it is necessary to develop a comparison group that closely matches that of the participant group.

Two samples were selected for the administrative data analysis: baseline data for the pre-implementation period was drawn using billing data in the months of December to March, 2001 and post-implementation data was drawn using billing data for the months of December to March, 2002[62]. The comparison population was to be constructed so as to match participating households. Matching between comparison and participating households was completed on the following basis[63]:

1. Region (by FSA or neighbourhood if possible);
2. Similar energy utilization profile prior to DSM as the participant households;
3. No address change/no change in customer account over the pre- and post-period (same customer/same household);
4. Exclude quasi non-participants[64];
5. Same account holder[65].

[62] Aggregate data were provided by BC Gas. Caveats associated with this data are described in Section 7.3. Outliers were not removed from the main analysis presented in this chapter, but were considered as part of additional analyses completed (see Section 7.5).
[63] Matching was done by BC Gas.
[64] Those applicants whose rebate application was rejected or pending were excluded from the impact analysis as well as from the survey.
[65] Limited matching was done by length of time with account with BC Gas (proxy for age of heating plant). Cases were removed if residents were not BC Gas customers through the pre- and post- implementation

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After construction of the comparison and participant samples, an analysis was done to identify energy savings for the participant population on a pre/post basis using a comparison group to establish the extent to which DSM households achieved greater energy savings than that of non-participating households.

7.3 Caveats / Limitations Associated with the Administrative Data and Analysis

There are a number of caveats that should be stated prior to reporting the results of the administrative data analysis. Specifically, a number of data issues could affect the results of this administrative analysis[66]. While the sample size utilized as part of the current analysis was substantial, only 14,779 Furnace Tune-up participants were successfully matched against the administrative data, out of 27,324 Furnace Tune-up participants in total (match rate of 54%[67]). Possible differences in match rates overall or within specific customer segments could have resulted in an administrative data sample that is not representative of the true Furnace Tune-up participant group.

In addition, due to the timing of this evaluation, energy usage in the pre- and post-implementation period was assessed using billing data from December to March[68]. As a result, the time period available in which to assess the effect of the program is limited. Because one goal of the program was to improve energy awareness and to educate customers about other activities that could be completed to save energy, longer-term energy savings resulting from the program would not be captured using such a short window of time.

Another caveat associated with the data involves regional differences with respect to how energy consumption is measured. Based on information from BC Gas, there are differences between Interior and Coastal areas in the way GJ consumption data are recorded. Specifically, billing data in the Interior is made up of a mix of actual (measured bi-monthly) and estimated GJ consumption and is billed monthly. In the Lower Mainland, GJ consumption is billed on actual bi-monthly measurements. Given the short period of time available for measuring the effect of the BC Gas 2001 Residential DSM Campaign, the averaging used in the Lower Mainland data, and the estimates employed for Interior consumption would have reduced the sensitivity of the data to changes that might have occurred as a result of the 2001 Residential DSM Campaign. Differences between the Interior and Lower Mainland in the way that GJ consumption is recorded or aggregated may reduce the ability of the current analysis to detect the precise GJ savings associated with each program.

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periods. Follow-up analysis was also conducted, weighting customers in the Furnace Tune-up and comparison groups by a proxy variable for length of time with BC Gas; however, this analysis using weighted data did not change the results presented in this report.

[66] Aggregate administrative data was provided by BC Gas and the Consultant had no first-hand experience with BC Gas databases/data extraction procedures.

[67] Matching completed by BC Gas.

[68] December, 2000 to March, 2001 for the pre-implementation period and December, 2001 to March, 2002 for the post-implementation period.

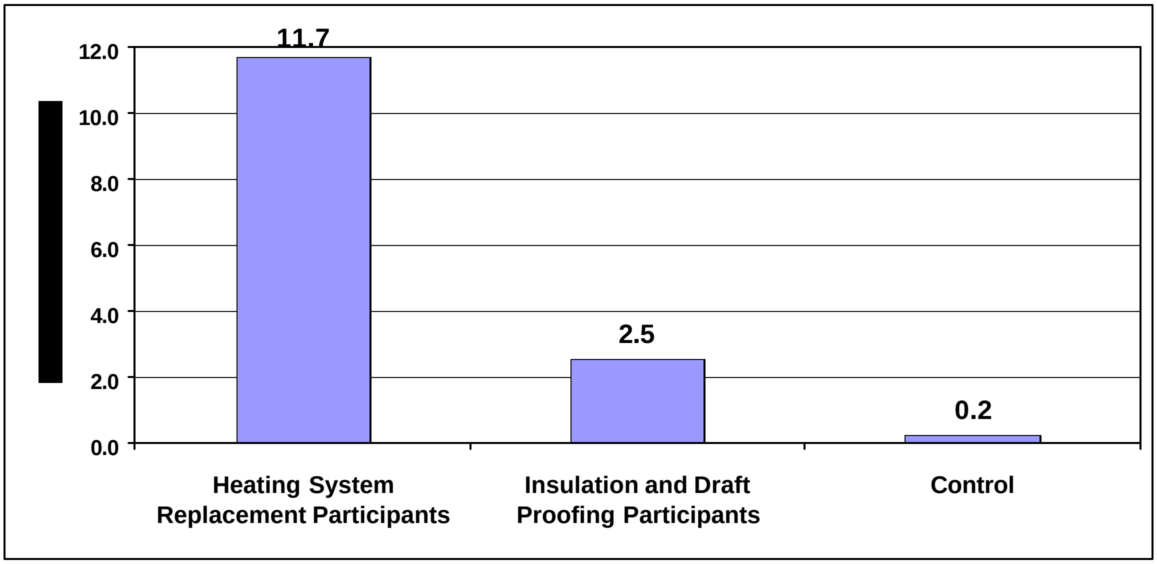
Additional caveats include the provision of non-normalized annual heating data, and anomalies associated with the annual energy consumption data provided[69]. Due to the limits of the data, caution should be used when interpreting the degree of savings associated with each program, including the Furnace Tune-up, Heating System Replacement and Insulation and Draft Proofing programs. It may be possible to increase the ability of the current analysis to measure decreases in energy usage caused by the BC Gas DSM programs by using a longer time period (e.g., possibly associated with additional applications of the program) or by improving match rates[70].

7.4 Data Analysis

The analysis showed that both the Heating System Replacement and Insulation and Draft Proofing programs resulted in significantly greater energy savings compared to the control group. Overall, participants in the Heating System Replacement program showed a decrease in energy consumption of 11.7 GJ during the December to March billing period, or 18.2%, and participants in the Insulation and Draft Proofing program showed a decrease in Winter energy consumption of 2.5 GJ (4.2%). Again, caution should be used in interpreting the magnitude of these effects, due to limitations in the data[71]. Chart 7-1 illustrates the average energy savings due to the Heating System Replacement and Insulation and Draft Proofing programs:

[69] Including the provision of annual GJ usage that included Lower Mainland customers only, and definition of the annual data in such a way as to include part of the implementation period. As a result, caution should be used in interpreting estimated annual GJ savings.
[70] Other measures, such as incorporating information from meter readings or conducting case studies to determine the effect of a furnace tune-up could be implemented; however, the cost of such measures could easily outweigh the possible benefits.
[71] Including low match rates between administrative data and program participant data as well as regional differences in measurement of energy consumption.

Chart 7-1
Average Winter Energy Savings due to Heating System Replacement and Insulation and Draft Proofing Programs[72]



The results of the Furnace Tune-up, Heating System Replacement and Insulation and Draft Proofing programs are presented in Table 7-1. Pre- and post-implementation energy consumption is presented, as well as the estimated GJ savings per household during the December to March billing period[73], percentage savings[74], and estimated Annual GJ savings.

Table 7-1
Administrative Data Analysis (GJ from December to March billing period)

Group	Number of Households	Number removed as incomplete[75]	Average GJ Consumption/household		GJ savings/ household – Dec-Mar Billing Period	% saving	Estimated Annual GJ Savings[1]
			Pre-program	Post-program			
Participant							
- Furnace Tune-up	14,779	132	55.3	55.7	(0.4)	NSD*	NSD*
- Heating System	732	7	64.22	52.56	11.7	18.2%	20.8
- Insulation	741	0	59.0	56.5	2.5	4.2%	4.5
Total Participant	16,252	139					
Comparison	16,252	155	56.0	55.8	0.2	0.4%	

* No significant difference/change

[72] December to March billing data (see Section 7.2).
[73] Sample period utilized for the current analysis.
[74] Percentage savings is based on pre-program energy usage.
[75] 294 individuals did not have both baseline and post-implementation energy usage data.

[1]Based on estimated annual GJ usage provided by BC Gas for Heating System Replacement participants (114.5 GJ) and for Insulation and Draft Proofing participants (107.9 GJ).

As highlighted in Table 7-1 above, participant households witnessed a marked decline in energy consumption relative to comparison households, as Heating System Replacement participants witnessed a decrease of 18.2% in energy consumption on a pre/post basis relative to a 0.4% decrease among the comparison households. Similarly, the savings in average energy consumption among Insulation and Draft Proofing participants (4.2%) was significantly different from the comparison population. In contrast, the analysis did not detect a statistically significant decrease in energy consumption due to the Furnace Tune-up program; however, in interpreting all of these results, the caveats presented in Section 7.3 should be considered.

7.5 Outlier Analysis

Results from the analysis of Furnace Tune-up participants indicated that there were no significant GJ savings as a result of the program. Again, the limitations in the data noted in Section 7.3 will affect the ability of the current analysis to detect the effect of a program expected to introduce energy savings of 2% to 5%. In order to further investigate this result, a number of analyses were conducted, removing outliers that might have influenced the results of this analysis[76]. When statistical testing was done between the comparison and Furnace Tune-up groups, after removing cases that showed more than a 20% change in energy usage, the comparison group showed an increase of 0.03 GJ in winter GJ consumption, and the Furnace Tune-up group showed an increase of 0.2 GJ. Statistical testing after removing outliers did not result in a significant decrease in energy consumption in the Furnace Tune-up group compared to the control group.

[76] Given that some homes may experience significant shifts in energy consumption due to factors other than technology/behavior (i.e., inclusion of a suite in the household, teenagers moving out of the household, etc.), analyses can be completed after removing outliers. Numerous analyses were completed of the change in energy usage for the Furnace Tune-up participant group using multiple definitions of "outlier". Specifically, analyses were completed after removing cases with more than 20% change in energy usage, as well as cases that were defined by SPSS as extremes.

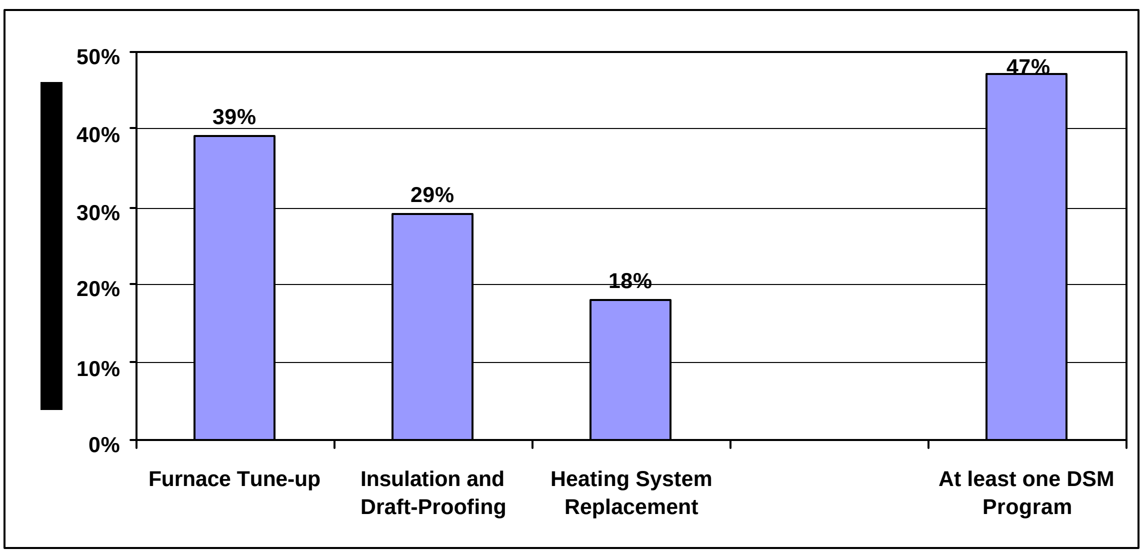
SECTION 8: BARRIERS TO PARTICIPATION

In order to gain a better understanding of why individuals did not or could not participate in any one of the DSM programs, non-participants were asked several questions pertaining to possible barriers to participation.

8.1 Non-Participation Issues

In general, it appears that the major barrier to participation in the BC Gas rebate programs was the lack of awareness of the program(s). For example, a significant proportion of non-participants noted that they were unaware of the Heating System Replacement program(59%), the Insulation and Draft Proofing program (75%) or the Furnace Tune-up rebate (72%). However, as highlighted in Chart 8-1, when they were informed about the respective program, a high proportion of non-participants indicated that they would have participated in such offers. This interest was highest for the Furnace Tune-up program, with 39% of non -participants who were unaware of this program indicating that they would have participated had they been aware of the program.

Chart 8-1
Proportion of Unaware Non-Participants
Who Indicated That They Would Have Participated in the Program
Had They Been Aware of the Program[77]



When considered as a percentage of all non-participants, 28% of non-participants indicated that they would have participated in the Furnace Tune-up program if they had been aware of this program, and 21% and 11% of all non-participants indicated that they would have

[77] Number of non-participants unaware of programs: Furnace Tune-up program – 404; Insulation and Draft Proofing program – 417; Heating System Replacement program – 323.

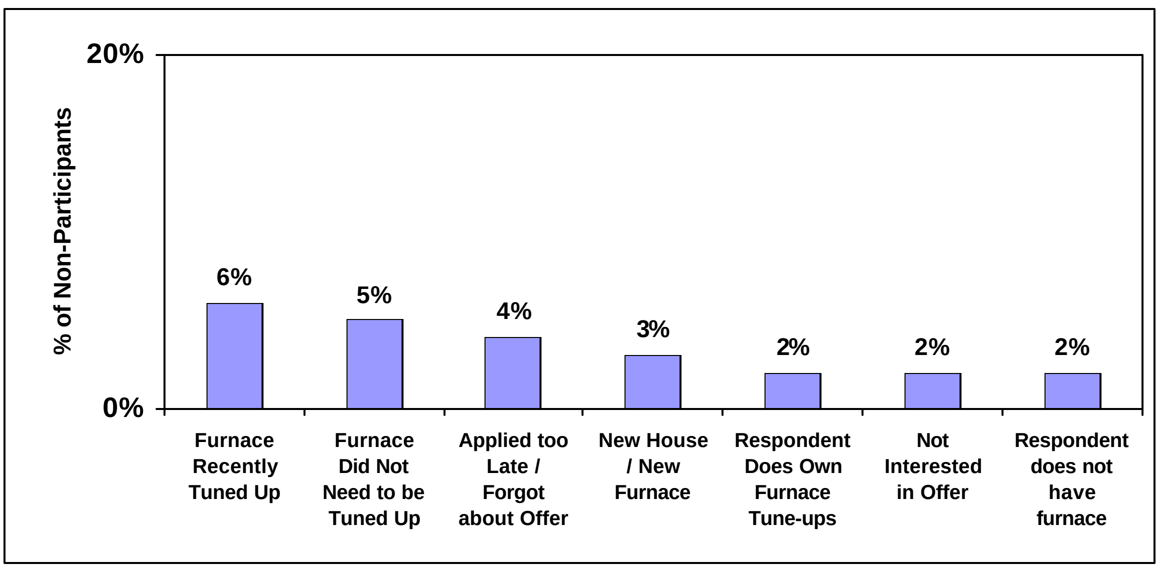
participated in the Insulation and Draft Proofing program and Heating System Replacement programs, respectively, if they had been aware of these programs.

Among those non-participants who were aware of the programs, the majority reported not needing the services or products for which BC Gas was offering rebates as the main reason for non-participation. Reasons such as late application, or the rebate being an inadequate incentive were also listed. Non-participants most commonly suggested that to encourage them to participate in future similar offers, BC Gas should improve communication/advertising of offers, offer higher rebates, and offer rebates again or extend the offer time frame.

8.1.1 Reasons Cited for Non-Participation (Among Non-Participants Who Were Aware of the Program)

A review of non-participant surveys indicated that the most common reason for non-participation in the Furnace Tune-up program was that the respondent had recently tuned up their furnace or that their furnace did not need to be tuned up. Chart 8-2 illustrates the reasons cited for non-participation in the Furnace Tune-up program.

Chart 8-2[78]
Reasons for Non-Participation in the Furnace Tune-up Program
(Among Non-Participants Aware of the Program)



The most common reason for non-participation in the Heating System Replacement rebate offer was that non-participants' current heating system was perceived as adequately efficient (14%). Chart 8-3 provides the reasons cited for non-participation in the Heating System Replacement program.

78 Open-ended response. Percentages do not sum to 100%.

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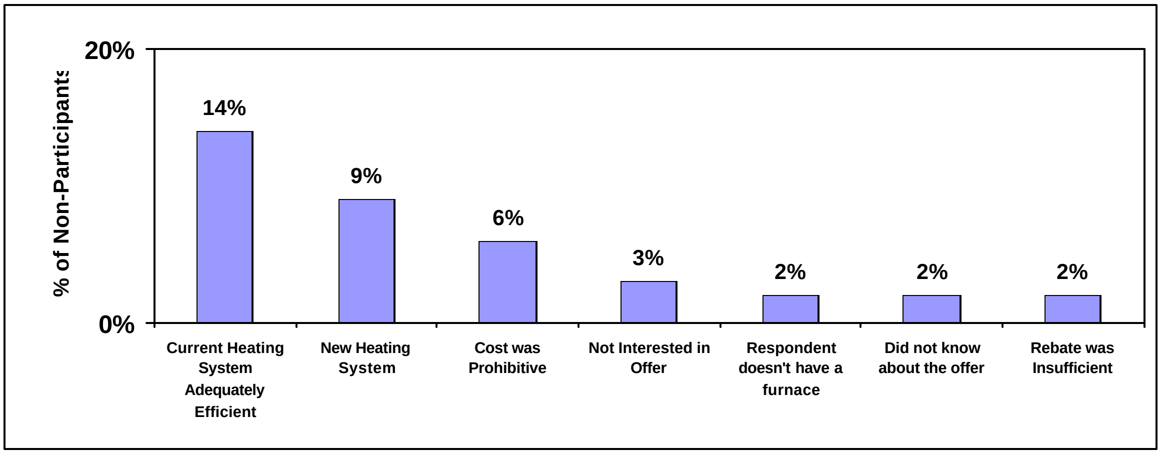
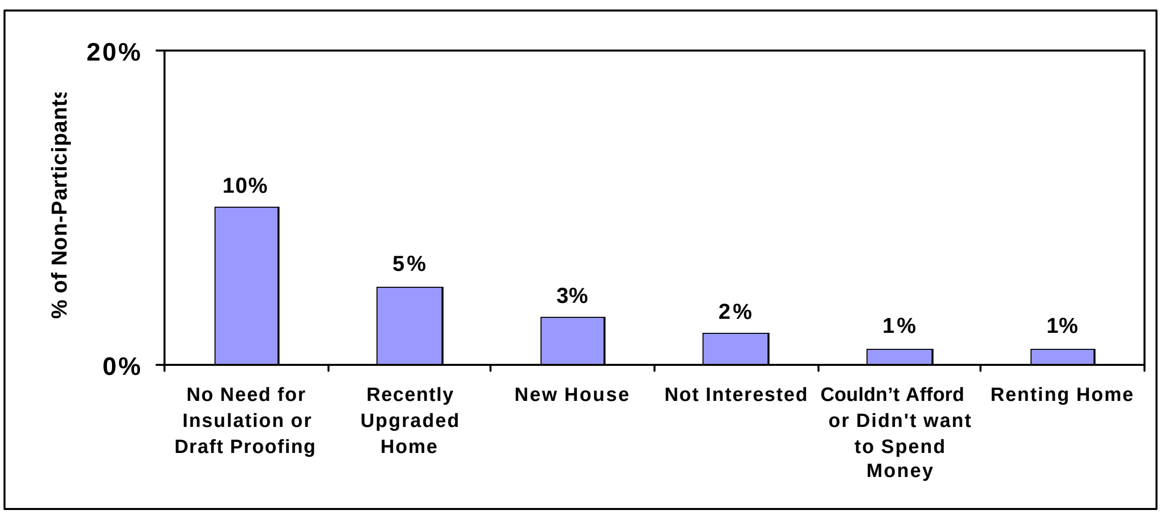
Chart 8-3
Reasons for Non-Participation in the Heating System Replacement Program
(Among Non-Participants Aware of the Program)



Finally, the largest group of non-participants reported that they did not participate in the Insulation and Draft Proofing rebate program because they had no need for insulation or draft proofing (10%). Chart 8-4 illustrates the reasons cited for non-participation in the Insulation and Draft Proofing program.

Chart 8-4
Reasons for Non-Participation in the Insulation and Draft Proofing Program
(Among Non-Participants Aware of the Program)



A selection of comments that concerned the reasons for not participating is provided below:

> *"We do not have any current problems with energy efficiency. Everything had been recently serviced."*

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> *"I figured that it would cost a couple thousand dollars to replace the heating system and the $150 wouldn't go very far."*

> *"I had already had new windows installed and the house was tested through BC Gas last year. I didn't need it."*

> *"I had replaced my furnace earlier that year and I didn't feel I needed these items."*

> *"I think it is burning very clean. I've had no indication that it is not operating efficiently."*

Participation in Future Programs

Approximately two-thirds of non-participants stated that they would be willing to participate in future energy-saving programs. When asked to comment on their willingness to participate in future energy-saving programs, 20% of non-participants indicated that they would be willing to participate if enough money could be saved (i.e., if the benefits outweighed the costs), followed by those who said they would participate if there was a need (12%)[79]. A selection of comments regarding non-participants' willingness to participate in future energy-saving programs is below:

> *"I would be willing to if it would lower my heating costs."*

> *"The price would have to be right and I would have to have a need for the energy saving feature."*

Among the 13% of non-participants who indicated that they were not willing to participate in future energy-saving programs, there was no common theme behind this disinterest. Some responses included:

- that they would not participate because they were renting or because their house was soon to be torn down (3%); or
- that they would not participate because their house was already energy efficient or because their gas bills were manageable (3%).

A selection of comments regarding non-participants' unwillingness to participate in future energy-saving programs is provided below:

> *"I pay the gas bill here but I am just renting the place. I do not think the landlord would be willing to do these things. It is not my responsibility. If I owned the property, I would be interested."*

> *"My place is relatively new and replacing the furnace is not at all in the books. We heat our place primarily with our gas fireplace."*

[79] The statement by non-participants that they would participate in BC Gas energy-saving programs if there was a need is consistent with reasons provided by participants for participating. The largest group of participants in the Furnace Tune-up and Insulation and Draft Proofing programs stated that they participated because their furnace needed to be tuned up (72%), or because they had decided to insulate prior to the program (54%). Participants in the Heating System Replacement program were most likely to state that they participated because their previous heating system was old (31%).

"I do not know what else I could do to make my place more energy efficient."

8.1.2 Identification of Measures/Actions that Could Have Encouraged Non-Participants to Utilize the Program

When asked how BC Gas could make non-participants aware of similar energy efficiency programs in the future, non-participants were most likely to suggest using bill inserts (45%). It should be noted that BC Gas did send inserts with bills to advertise all three rebate programs. Other common suggestions were:

- Direct mail from BC Gas separate from the bill (12%);
- Newspaper ads (8%);
- TV ads (5%);
- Website / Email (4%); and,
- Phone call from BC Gas (4%).

Non-participants also suggested ways for BC Gas to encourage them to participate in similar energy efficiency programs in the future. Suggestions by non-participants included:

- Improve communication / advertising of offers (18%);
- Provide higher rebates (15%);
- Offer rebates again / Extend offer time frame (12%); and,
- Provide more information on direct benefits of energy efficiency (9%).

As well, some non-participants said that BC Gas could do nothing to encourage them to participate in similar programs, either because they felt that they would participate if there was a need (6%), or because they were in rental accommodation or a new house.

Some responses included:

> *"They could make me aware of the programs to encourage me to participate in them."*
>
> *"They could offer similar energy efficient programs and increase the amount of rebate that is offered."*
>
> *"I need to see if it has some value to me. I'm not sure how much a new furnace would cost, and I'm sure $150 is small compared to its price. If I knew what the future paybacks were for such a furnace, I might consider it."*
>
> *"BC Gas cannot do anything to encourage me to participate in energy efficiency programs. If the time is right for me to make repairs or upgrades then I will participate in energy efficiency programs."*

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8.2 Barriers to Participation – Key Issues

- **Lack of Awareness was a major reason for non-participation in the program.** Overall, a key reason for non-participation in the program(s) was due to a lack of awareness about the specific programs. In particular, a significant proportion (47%) of non-participants who were unaware of the program noted that they would have participated in at least one of the three programs (most likely the Furnace Tune-up) had they been aware of the program.

- **Non-participants also reported not needing the maintenance featured as part of the BC Gas DSM Campaign as a reason for not participating in the program(s).**

  The most common reason for non-participation in the Furnace Tune-up, Heating System Replacement and Insulation and Draft Proofing programs among non-participants that were aware of the programs was that non-participants did not need these products or services. Other non-participants reported applying too late to the program, or not being interested in the offer. For the Heating System Replacement program, non-participants also indicated that the cost of a new heating system was prohibitive or that the rebate was insufficient.

- **Non-participants expressed the highest levels of interest in the Furnace Tune-up program.**

  Nearly three in ten non-participants indicated that they would be interested in the Furnace Tune-up rebate program, compared to two in ten for the Insulation and Draft Proofing program, and one in ten for the Heating System Replacement program. Participants indicated that they would be more likely to participate if enough money would be saved because of the maintenance, or if they had a need for the maintenance work.

  Overall, two-thirds of non-participants indicated that they would be willing to participate in future energy-saving programs.

- **Non-participants indicated that improved communication or higher rebates would encourage them to participate in energy-saving programs.**

  Eighteen percent of non-participants suggested improved communication or advertising, and 15% identified higher rebates as an approach to encourage additional residents to participate in future energy-saving programs. Other suggestions provided by non-participants included offering the rebates over a longer time period, providing more information on the direct benefits of energy efficiency and offering reduced gas prices.

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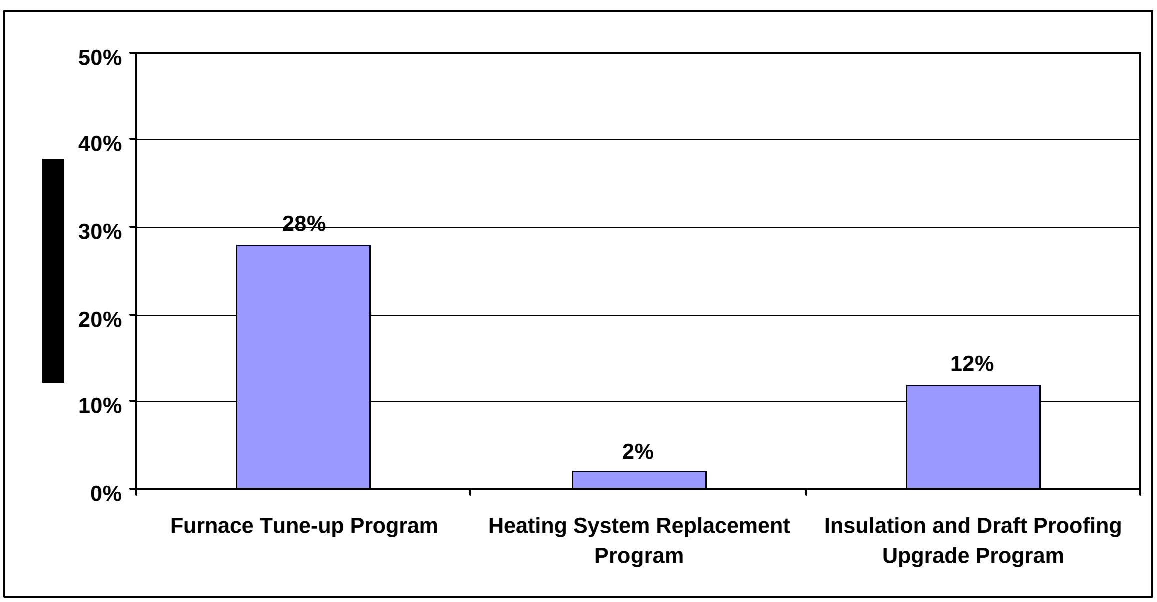
SECTION 9: ESTIMATION OF FREE RIDER/FREE DRIVERS

Analysis was undertaken to evaluate the "incremental" impact of the BC Gas 2001 Residential DSM Campaign. This analysis included a measure of the activity that would have likely occurred even in the absence of the program (estimate of "free ridership") as well as an evaluation as to the extent to which the program resulted in additional energy-saving activities completed by customers as a result of the program (estimate of "free driver" impact).

9.1 Estimation of Free Ridership

Of BC Gas customers who did not participate in any of the rebate programs[80], 28% reported that they had completed a furnace tune-up between May 22 and September 15, 2001. In contrast, only 2% of non-participants had replaced their furnace with a natural gas high-efficiency central heating system between September 15 and November 30, 2001. Finally, 12% of non-participants reported that they had upgraded their home with $75 or more of insulation and draft proofing materials between September 15 and November 30, 2001. As presented in Chart 9-1, these numbers can be taken as baselines for free riders for the Furnace Tune-up, Heating System Replacement, and Insulation and Draft Proofing programs, in that it can be assumed that these represent the percentage of BC Gas customers who would have completed these activities regardless of the presence of the program.

Chart 9-1
Percentage of Non-Participants Reporting Energy Saving Activities



[80] As estimated based on the Non-Participant Survey

9.2 Estimation of Free Drivers

As part of the current evaluation, free drivers were defined as additional energy-saving activities completed by the customer as a result of participation in the 2001 Residential DSM Campaign (e.g., installing or maintaining a gas fireplace, checking or installing weather stripping, etc.). As indicated in Table 9-1, a greater percentage of Furnace Tune-up participants reported completing or planning to complete at least one energy-saving activity (25%) compared to Heating System Replacement participants (9%) or Insulation and Draft Proofing program participants (12%). Table 9-1 indicates that checking or installing weather stripping was the most common energy-saving free driver reported by Furnace Tune-up (6%) and Heating System Replacement (3%) program participants[81]. Participants in the Furnace Tune-up program were also more likely to report caulking exterior doors and/or windows (5%). Participants in the Insulation and Draft Proofing program were more likely to report replacing the air filter (3%) or installing new energy-efficient windows (3%).

Table 9-1
Energy-Saving Activities as a Result of BC Gas rebate program

Energy saving activity	Furnace Tune-up participants	Heating System Replacement participants	Insulation and Draft Proofing participants
Encouraged to complete or plan one or more energy-saving activities (Yes)	25%	9%	12%
Check or install weather stripping	6%	3%	n/a
Caulk exterior doors and/or windows	5%	1%	n/a
Install programmable thermostat	4%	2%	1%
Replace the air filter	4%	1%	3%
Replace the furnace	3%	n/a	1%
Upgrade the insulation	2%	3%	n/a
Install or maintain a gas fireplace	2%	2%	1%
Install new energy-efficient windows	2%	1%	3%

Customers participating in the Heating System Replacement program were also asked specifically about whether they had installed a programmable thermostat with their new heating system. Forty-four percent of the new natural gas high-efficiency heating systems included programmable thermostats with them, and 71% of these respondents installed the thermostats at the same time as their new heating system. A further 15% of respondents whose heating systems did not include these thermostats had them installed with their heating system at the time[82].

[81] Upgrading the insulation was also mentioned by 3% of Heating System Replacement program participants.
[82] In comparison, 67% of contractors reported installing programmable thermostats for customers who participated in the Heating System Replacement program, and more than three-quarters of Heating System Replacement contractors (78%) reported programming thermostats for customers every time they installed programmable thermostats (only 6% reported never programming them).

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9.3 Estimation of Free Riders / Free Drivers – Key Issues

- **Free ridership was highest for the Furnace Tune-up rebate program.** Specifically, 28% of non-participants reported that they had completed a furnace tune-up between May 22 and September 15, 2001. In contrast, 2% of non-participants reported replacing their heating system with a natural gas high-efficiency heating system, and 12% reported upgrading their home with $75 or more of insulation and draft proofing materials between September 15 and November 30, 2001.

- **With respect to free drivers, more participants in the Furnace Tune-up program reported completing or planning to complete additional energy-saving activities as a result of the program compared to the other DSM programs.** One-quarter of Furnace Tune-up program participants reported completing or planning to complete at least one energy-saving activity compared to participants in the Heating System Replacement program (9%) or Insulation and Draft Proofing program (12%). The most common free drivers included checking or installing weather stripping, replacing the air filter, and caulking exterior doors and/or windows.

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SECTION 10: ENERGY USE, PRACTICES AND PERCEPTIONS

Data was collected from participants concerning their perceived level of awareness of energy conservation issues and practice of energy efficiency. Almost all respondents reported high levels of awareness. With respect to energy conservation practices, households were most likely to report replacing their air filter.

10.1 Energy Use, Practices and Perceptions

As highlighted in Table 10-1, almost all respondents reported awareness of energy issues and active practices of energy efficiency. A majority of respondents also felt it was important to use energy efficiently in the home and that it was important for BC Gas to encourage customers to practice energy efficiency. As highlighted in the Table, program participants tended to be more aware of energy issues than were non-participants.

Table 10-1
Energy Use Practices and Perceptions

	Furnace Tune-up participants	Heating System Replacement participants	Insulation and Draft Proofing participants	Non-Participants
Aware of Energy Conservation Activities to Practice at Home as Result of Program[83]	58%	42%	45%	n/a
Important/Very Important to Use Energy Efficiently in the Home	95%	93%	97%	94%
Aware of Energy Issues Facing Community[84]	93%	90%	92%	82%
Know how to use Energy Efficiently Around Home[85]	90%	92%	92%	83%
Household Practices Energy Efficiency[86]	89%	84%	86%	73%
Feel it is important/very important for BC Gas to encourage Energy Efficiency	96%	92%	92%	87%

The role of the rebate in raising customer awareness about the need for Furnace Tune-ups may be particularly useful, as less than half of contractors felt that their customers were aware or very aware of the need for regular Furnace Tune-ups (44%). Forty percent of

[83] Percentage of respondents who agreed or strongly agreed with the statement "As a result of the rebate program, I am more aware of energy conservation activities that I can practice in the home."
[84] Percentage of respondents who agreed or strongly agreed with the statement "I am aware of the energy issues facing my community such as high energy costs and environmental issues."
[85] Percentage of respondents who agreed or strongly agreed with the statement "I know how to use energy efficiently around my home (both indoor and outdoor).
[86] Percentage of respondents who agreed or strongly agreed with the statement "My household actively practices energy efficiency."

contractors surveyed for the Furnace Tune-up program rated their customers' awareness of the need to have their furnace tuned up as neutral, and 14% responded that their customers were unaware or not at all aware.

10.2 Energy Use Profile

When asked whether their household had completed various energy-saving activities, the majority of individuals surveyed (both participants and non-participants) reported replacing their air filter. Table 10-2 highlights the frequency with which households reported various energy-saving activities. Again, program participants tended to be more pro-active in terms of undertaking energy-saving activities than were non-participants.

Table 10-2
Completion of Energy-Saving Activities[87]

	Furnace Tune-up participants	Heating System Replacement participants	Insulation and Draft Proofing participants	Non-Participants
Installed a programmable thermostat	31%	69%	48%	38%
Replaced air filter	84%	64%	86%	77%
Replaced the furnace	14%	n/a	32%	17%[88]
Checked or installed weather stripping	61%	71%	n/a	61%
Caulked exterior doors and/or windows	46%	61%	n/a	45%
Upgraded the insulation	29%	40%	n/a	25%
Installed new energy-efficient windows	32%	40%	49%	38%
Installed or maintained a gas fireplace	52%	41%	39%	40%

[87] Represents percentage of respondents that reported completing these activities.
[88] Two percent of non-participants reported replacing their heating system with a natural gas high-efficiency central heating system between September 15 and November 30, 2001.

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SECTION 11: SUMMARY OF FINDINGS

Highlighted below are the key findings associated with the evaluation of the BC Gas 2001 Residential DSM Campaign.

There is a high level of support for the various BC Gas programs.
Overall, individuals who participated in the program (both households, contractors and manufacturers) were very supportive of the program and expressed high levels of satisfaction with each program.

BC Gas should examine promotions, advertising and rebate levels to encourage greater participation.
The key reason for limited participation in some of the BC Gas DSM programs can be traced to a lack of awareness of the programs. In fact, almost one-half of non-participants (47%) who were unaware of the program noted that they would have been interested in participating in at least one of the three programs had they been aware of the program.

Notwithstanding the lack of awareness, it appears that there is scope for BC Gas to review the appropriateness of the rebates provided under the Heating System Replacement program and Insulation and Draft Proofing program. For example, the BC Gas rebate under these programs typically represented only 5% of the total cost of the project for the homeowner. In contrast, the $25 Furnace tune-up rebate represented a much higher (28%) proportion of the total cost of the furnace tune-up.

On a net incremental basis, two of the DSM programs have generated energy savings.
Using administrative data and analysis of changes in consumption on a pre/post basis for both participants and comparison households, it appears that participation in the Heating System Replacement program and Insulation and Draft Proofing program has resulted in statistically significant decreases in energy consumption in these households relative to comparison households. However, it must be noted that data issues identified as part of this report limited the ability of the present analysis to measure exact energy-savings resulting from the 2001 Residential DSM Campaign. More research could be completed on a case study basis to further explore the energy impacts associated with furnace tune-ups. In addition, it may be possible to increase the ability of the current analysis to measure decreases in energy usage caused by the BC Gas DSM programs by using a longer time period (e.g., possibly associated with additional applications of the program) or by improving match rates.

BC Gas programs have other important benefits.
In addition to the energy-savings identified by the Consultant, program participants attributed several additional positive benefits/impacts to their participation in the program, including:

- accelerated maintenance/replacement of systems;
- better understanding/awareness of energy issues;
- greater disposition to/likelihood of implementing other energy-saving activities in the future relative to non-participants.

APPENDIX C

RESPONSE TO LOWER MAINLAND LARGE GAS USERS ASSOCIATION ET AL INFORMATION REQUEST No. 1, QUESTION #48.1

BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, British Columbia
Canada V3S 2X7

Tel 604-576-7000
Fax 604-592-7890

April 11, 2003

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. R.J. Pellatt
Commission Secretary

Dear Sir:

Re: Review of BC Gas Utility Ltd.'s Compliance with the BCUC Code of Conduct and Transfer Pricing Policy

In accordance with Part 7 of the BCUC Code of Conduct and Transfer Pricing Policy for the Provision of Utility Resources and Services, BC Gas respectfully submits the enclosed compliance review as conducted by its Internal Audit Services.

We trust the enclosed is satisfactory. Should further information be required, please contact the undersigned at (604) 592-7784.

Yours very truly,

BC GAS UTILITY LTD.

Original signed by

Scott Thomson, Vice President
Finance and Regulatory Affairs

Attachments

BC Gas Inc.
1111 West Georgia Street
Vancouver, British Columbia
Canada V6E 4M4

Internal Audit Services
Tel 604-443-6500
Fax 604-443-6549

April 11, 2003

Randy Jespersen
President
BC Gas Utility Ltd.
Surrey Operations Centre

Subject: Review of BC Gas Utility Ltd.'s Compliance with the BCUC Code of Conduct and Transfer Pricing Policy.

Internal Audit Services has recently completed a review of compliance with the BC Gas Utility Ltd. Code of Conduct and Transfer Pricing Policy for the Provision of Utility Resources and Services (the BCUC Policies). This review was conducted to enable BC Gas Utility Ltd. to meet the requirements of Part 7 of each of the BCUC Policies. The requirements state that "BCGUL will monitor employee compliance with this Code by conducting an annual compliance review, the results of which will be summarized in a report to be filed with the Commission within 60 days of the completion of this review".

Background

The BCUC Policies were issued in 1997 to provide guidance to BC Gas Utility Ltd employees on interactions with Non-Regulated Business ("NRBs"). NRBs are defined as "an affiliate of the Utility not regulated by the Commission or a division of the Utility offering unregulated products and services". Since that time the Utility has worked to create processes and procedures that would ensure compliance with these policies.

In prior years, reviews of compliance with the BCUC Transfer Pricing Policy and the Code of Conduct were included as part of the scope of internal audits of individual Utility business units or as requested by the Commission. In 2002 a separate review of all aspects of the BCUC Policies was undertaken.

Objectives, Scope and Approach

The objectives of the review were to ensure that the business processes in place facilitate and support compliance with the BCUC Policies. Our approach consisted of substantive procedures related to the requirements regarding sharing of customer information, cross charging time to NRBs for services performed and special arrangements provided to BC Gas customers by NRBs. Our procedures were focused on areas of the Utility which, based on our knowledge of the business, represented the greatest potential risk of non-compliance.

Conclusion

Overall BC Gas Utility Ltd has appropriate business processes in place to facilitate and support compliance with the BCUC Policies. Based on the results of our work, we believe that there is a high level of compliance with the Policies. There are, however, areas of the Utility where awareness of the BCUC Policies is lacking and where we have identified improvements that would increase awareness and understanding of the Policies and thereby increasing the level of compliance with the Policies.

Results of Work

As part of the review, Internal Audit Services selected a judgemental sample of 12 employees who were asked to respond to a survey on compliance with the BCUC Policies. The sample was not representative of the Utility as a whole. Instead, Internal Audit Services selected the participants based on whether their roles and responsibilities might require them to perform work for NRBs. Responses were received from all twelve of the employees surveyed. Three employees noted exceptions which have been summarised below:

Three employees indicated that they were not cross charging time for work performed for non-regulated businesses in the year. These employees indicated that they were not fully aware of the requirements of the BCUC Policies. The total value of time not charged was $2,984.

Subsequent to this review Internal Audit Services was informed that after becoming aware of the requirements, employees made adjustments to 2002 time records and appropriately charged time for services provided to non-regulated businesses in the year.

In addition to the work described above, further assurance regarding compliance with the policies was obtained through a compliance review of the BC Gas Inc. Code of Business Conduct. This is an annual process which covers all business units within the BC Gas group of companies. In 2002 the compliance process included 120 BC Gas Utility employees (generally all members of middle and senior management, but also including all employees in business units that were considered by Internal Audit Services to be high risk because of the nature of their work). As part of the process in 2002, Utility employees were specifically reminded that by signing off compliance with the BC Gas Inc. Code of Business Conduct they were also indicating their compliance with the BCUC Policies.

Recommendations

Based on the results of the work we performed for this review and discussions with Scott Thomson, Vice President, Finance and Regulatory Affairs, we believe the following process improvements will increase awareness and compliance with the BCUC Policies.

1. Effective January 1, 2003 all Utility time sheets were modified as of to include a positive check off relating to time spent on non-utility projects.
2. A point of contact has been designated as a resource for all Utility employees to provide guidance to ensure compliance with the Code of Conduct and Transfer Pricing Policy. Laurie Gray, Manager Regulatory Administration has accepted this role.
3. The Utility will continually communicate and reinforce the requirements of the BCUC policies to all employees. The Business Leaders/Manager Forums and Budget Process Information Seminars are both good examples of when the BCUC Policies will be communicated. At the Spring 2003 Manager’s Forum, Scott Thomson will discuss the BCUC Policies and introduce Laurie Gray as a resource for Utility employees should they have any difficulty in interpreting the BCUC Policies.
4. In future years the BC Gas Inc. Code of Business Conduct annual compliance process will be extended to include all Utility employees. Utility employees will be asked to certify their compliance with the BC Gas Inc. Code of Business Conduct and the BCUC Policies. In April 2003, all computer users will have to acknowledge understanding and compliance with the Code of Conduct and Transfer Pricing on a quarterly basis through a user acceptance screen during the network login process.

We wish to express our appreciation to all BC Gas Utility Ltd employees who participated in this review for their assistance and co-operation during the course of our review. Please contact me if you should have any questions or would like to discuss further the substance of our review.

Ewan R. Wilding
Director, Internal Audit Services
BC Gas Inc.
(604) 443-6601

cc: John Reid
Milton Woensdregt
Ian Anderson
Steve Richards
Scott Thomson
Guy Elliot, KPMG

APPENDIX D

RESPONSE TO LOWER MAINLAND LARGE GAS USERS ASSOCIATION ET AL INFORMATION REQUEST No. 1, QUESTION #48.2

Cross Charging

Scott Thomson

Revenue Requirement Hearing - Concerns Expressed

- **Procedures on Code of Conduct**
- **Procedures on Transfer Pricing Policy**
- **Utility contracting for services from Inc.**

Company Response

- **Timesheets revised – check one of two boxes**
  - **"I confirm I have recorded time spent on non-utility work to an order for cross-billing"**
  - **"All work was for Utility"**
- **Internal Audit - targeted sample of employees**
  - **High level of compliance with CoC/TPP overall**
  - **Additional awareness and focus required**

BC Gas™ NATURALLY RESOURCEFUL

Code of Conduct

- **Use of Confidential Information**
- **No Favoured Treatment**
- **Use of Utility Name**
- **Compliance and Complaints**

- **[Intranet–under Regulatory & Rate Guides]**

4
filename

Restrictions on Use of Confidential Information:

- No sharing of confidential information without customer consent.
- Information must be provided to all market participants in a similar manner - no preferential treatment to NRB.
- Aggregated customer information may be provided subject to paying appropriate transfer price.
- Non-customer specific information may be provided subject to paying appropriate transfer price.

No favoured treatment by Utility to a customer using an NRB

Utility will not preferentially direct customers to NRB

BC Gas not to undertake financing/other risks w/o appropriate BCUC-approved compensation

Limitation on use of Utility name as primary identifier

Equitable distribution system access must be maintained

Compliance and complaints:

- BC Gas required to advise employees of expected conduct
- BC Gas to monitor employee compliance
- Complaints from third parties to Scott Thomson
- BC Gas given 30 days to respond
- BCUC to adjudicate

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Transfer Pricing Policy

- **Companion to Code of Conduct**
- **Guards against Utility subsidization of NRB**
- **Sets out Pricing Rules**
- **Transfer of Activities**
- **Value to Utility and employees – transfers**

- **[Intranet–under Regulatory & Rate Guides]**

Companion policy to Code of Conduct intended to ensure that Utility and its customers receive adequate compensation for resources provided

Guards against subsidization of NRB activities by Utility

Approved by the BCUC

Sets out Pricing Rules for utility based on:

- Tariff price if available
- Full cost or market price, or
- Special price approved by BCUC

Also addresses costs relating to the transfer of activities:

- Transfer Costs
- Research Costs
- Development Costs

Policy recognizes value to utility and employees of flexibility in employment:

- Rotational Transfers
- Non-Rotational Transfers
- Human Resource Sharing

Consequences of Violation

- Impaired relationship with Regulator
- Erosion to relationship with trades & stakeholders
- Potential restrictions - Utility staff for NRB activity
  - Higher costs, reduced effectiveness - Utility and NRB
- Increased regulatory scrutiny/reduced flexibility
- Reduced ability to deliver on other key regulatory and operational initiatives:
  - PBR, Rate Design, Unbundling
  - CPCNs

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"Black & White" Examples

1. Can I provide confidential customer information to an NRB without the customer's consent?

2. Can I link the utility service to the NRB business?

"Black & White" Examples

THIS IS THE QUESTION SLIDE, ANSWER SLIDE FOLLOWS.

1. Can I provide confidential customer information to an NRB without the customer's consent?

No. "This Code precludes Utility from releasing confidential customer specific information without the consent of that customer." BC Gas employees must treat customer information as confidential, even in relation to an NRB.)

2. Can I link the utility service to the NRB business?

No. "Utility will not provide to an NRB any information that would inhibit a competitive energy services market from functioning". NRB business must be kept at arms length from BC Gas.

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"Black & White" Examples

1. **Can I provide confidential customer information to an NRB without the customer's consent?**
   - **No. "This Code precludes Utility from releasing confidential customer specific information without the consent of that customer."**

2. **Can I link the utility service to the NRB business?**
   - **No. "Utility will not provide to an NRB any information that would inhibit a competitive energy services market from functioning".**

"Black & White" Examples

THIS IS THE ANSWER SLIDE.

THE QUESTION SLIDE IS PRIOR TO THIS SLIDE.

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Grey Zone Example

1. **If a customer requests more information on NRB-related services or products, can I refer the customer to an NRB?**

Example - "Grey Zone"

THIS IS THE QUESTION SLIDE, ANSWER SLIDE FOLLOWS.

(No, not on an exclusive NRB-only basis, but yes, if you follow a specific procedure. In this case, you can provide the name of an NRB as part of a list of at least three companies that can provide the customer with the requested services or products. This preserves the "competitive energy services market" identified in the second Black and White example.)

"Utility will not provide to an NRB any information that would inhibit a competitive energy services market from functioning".

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Grey Zone Example

1. If a customer requests more information on NRB-related services or products, can I refer the customer to an NRB.

- **No, not on an exclusive NRB-only basis, but yes, if you provide the name of an NRB as part of a list of at least three companies who can each provide the customer with the requested services or products. This does not violate the "competitive energy services market" and gives the customer a choice.**

Example - "Grey Zone"

THIS IS THE ANSWER SLIDE.

THE QUESTION SLIDE IS PRIOR TO THIS SLIDE.

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What about my work?

- **Does my work relate to Utility or Inc?**
  - **If work relates only to Utility, charge time to Utility**
    - **(e.g. BC Gas CPCN)**
  - **If work is for NRB, charge NRB**
    - **(e.g. Consulting for Oman)**
- **If work seems to relate to both Utility and NRB or Inc, consider the context: If NRB did not exist, would Utility still do this work?**
- **If in doubt, contact: Laurie Gray
Regulatory Services**

If there is a clear distinction, charge the appropriate entity.

If there is a grey area, ask yourself the question, "If the NRB did not exist, would Utility still do this work?" Often the answer will be yes, Utility would still do this work.

Next Steps

- Increased Internal Audit Focus in future years
- Enhanced annual compliance
- Currently developing an Intranet screen similar to "Use of BC Gas Technology Information Assets"
  - First compliance screen in next few weeks