Terasen Gas

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August 13, 2009

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: Terasen Gas Inc. ("TGI", the "Company"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW")
Collectively the "Terasen Utilities"
Return on Equity and Capital Structure Application (the "Application")

Response to the Commercial Energy Consumers Association of British Columbia ("CEC") Information Request ("IR") No. 2

On May 15, 2009, the Terasen Utilities filed the Application as referenced above. In accordance with the British Columbia Utilities Commission Order No. G-70-09 setting out the Regulatory Timetable for the Application, the Terasen Utilities respectfully submit the attached response to CEC IR No. 2, in advance of the August 14, 2009 deadline.

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

Sincerely,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC. and
TERASEN GAS (WHISTLER) INC.

Original signed by:

Scott A. Thomson
Vice President, Regulatory Affairs & CFO

Attachments

cc (email only): BCUC and Registered Parties

1.0 Reference: CEC IR #1.7.1 to 1.8.2

1.1 In the event a negotiated settlement process is undertaken in this proceeding, does Terasen foresee an opportunity to negotiate an AAM formula which may be acceptable to TGI?

<u>Response:</u>

As discussed on pages 33 and 34 of the Application, Terasen is not proposing an automatic adjustment mechanism at this time. It is possible that through the course of a negotiated settlement, the parties to the settlement could bring forward ideas that would result in the development of a workable AAM formula that would be acceptable to the Terasen Utilities.

The primary purpose of this Application is to set a fair return for the Terasen Utilities at the present time. An automatic adjustment mechanism periodically resets the allowed return in the future. It is paramount that the results of the current formula be varied as it is not resulting in a fair return, and a new benchmark must be established that does, as applied for, result in a fair return.

2.0 Reference: CEC IR #1.12.1 – Business Risk

2.1 Please comment on the implication of the Commission's direction in the 2008 LTAP decision at page 179 which directs that BC Hydro undertakes "the necessary analysis to establish the cost effectiveness, or lack thereof, of DSM programs to achieve the apparent economic potential of Electrical Load Avoidance DSM for space and water heating applications in new residential construction (including multi-unit dwellings) and new small commercial applications. That analysis should focus on high efficiency, natural gas fired appliances compared with electrical based board heating applications".

Response:

The referenced portion of the BCUC Decision on BC Hydro's 2008 LTAP arose from Terasen's intervention in the LTAP proceeding. The Terasen submissions were based on evidence in the LTAP proceeding taken from BC Hydro's 2007 Conservation Potential Review that there was a large amount of economic potential in BC for the direct use of natural gas to displace or avoid electrical heating load but that there was no achievable potential. The Commission determination in the LTAP Decision with respect to Electric Load Avoidance (ELA) DSM effectively granted the Terasen Utilities' request in this matter. BC Hydro had made submissions in the LTAP proceeding that the provisions in the Utilities Commission Act with respect to long term resource plans and expenditure schedules did not provide the Commission with the power to order a utility (BC Hydro in this case) to implement a program or carry out a plan that it had not applied for. Rather, the Commission's jurisdiction is limited in long term resource plan proceedings (the LTAP in this case) to accepting or rejecting the plan, or accepting or rejecting a portion of the plan. The Terasen Utilities did not dispute BC Hydro's submissions on the Commission's jurisdiction to order BC Hydro to carry out a different plan or program than applied for in the LTAP and therefore concluded that it should seek to have the Commission require BC Hydro to conduct a study on ELA DSM and come back in the next LTAP with plans to implement any ELA DSM programs found to be cost-effective. The Terasen Utilities also asked for Commission to require BC Hydro to continue to file LTAPs on a 2-year cycle between filing dates so that the matter of ELA DSM would not languish without resolution for longer than necessary. The Commission LTAP Decision accommodates the Terasen Utilities' request by requiring the next LTAP to be filed on or before June 30, 2010 however in the future BC Hydro may seek approval to amend the 2-year LTAP filing cycle if it wishes.

The Terasen Utilities consider it a positive development that BC Hydro will be conducting a study on ELA DSM prior to the June 30, 2010 filing date of the next LTAP. TGI is hopeful that the study will yield valuable information to inform the DSM plans and activities of both electric and gas utilities going forward. However all BC Hydro is required to do is to perform a study of ELA DSM. There is no certainty as to what the findings of the study will be and there is no certainty that if the study produces results favourable to the direct use of natural gas or alternative energy sources that relevant programs of any material size will be implemented.

While the LTAP Decision included some determinations that are favourable to the Terasen Utilities position it also included other determinations that create uncertainty going forward. For example, since the LTAP Decision did not approve BC Hydro’s requests with respect to the Clean Power Call there is now more uncertainty as to how and when an updated value for the marginal cost of new electricity supply will be determined and therefore how and when updated marginal cost pricing will be reflected in rate structures such as the RIB Step 2 rate.

3.0 Reference: CEC IR #1.20.1

3.1 Would it be useful to Terasen to work with impacted customer groups to attempt to balance Terasen's competitive position versus other options and consequently mitigate this business risk through developing a more level playing field?

Response:

Terasen endeavors to work with its customer groups on a broad range of issues. It is not clear how this question relates to the referenced question which asks if Terasen has used BC Hydro's LTAP 10 year price increase information to project out the competitive position of natural gas versus electricity. Terasen must offer its customers a market priced commodity option, BC Hydro offers an historic cost based energy form that is not currently market priced and is unlikely to be for the foreseeable future. Nor would it be in the financial interest of impacted customers to see their electricity rates move to market pricing.

4.0 Reference: BCUC IR# 1.1.3

It is time to establish an appropriate and fair return. The mechanics of a robust formula that can operate successfully in all market conditions is a matter for a future regulatory proceeding and will be in part dependent on the outcome of this proceeding.

4.1 How will a robust formula be dependent on the outcome of this proceeding?

Response:

A robust formula that will continue to provide fair and appropriate returns must be based on a point of departure that itself is a fair and reasonable starting point. If this proceeding fails to produce a fair and reasonable return, it would not be reasonable to expect that an automatic adjustment mechanism would correct for that and produce fair and reasonable returns.

5.0 Reference: BCUC 1.3.3

Please refer to the table which follows for a summary of TGI's allowed ROE and actual ROE from 1992 to 2008, inclusive of the record of incentives earned and the impact of these incentives on the percentage of actual ROE earned.

5.1 The response material the CEC obtained did not have a table attached was there supposed to be a table responding to this question or is there another reference to pick up this information?

Response:

Please refer to the response to BCUC IR 2.91.1 which now contains the table that was inadvertently omitted from the original response to BCUC IR 1.3.3.

6.0 Reference: BCUC IR# 1.3.4

The dollar impact of the proposed increase in equity thickness from 35.01 percent to 40 percent and ROE from 8.47 percent to 11.00 percent is approximately $44.9 million of revenue requirement for TGI. This translates to an approximate delivery rate impact of 8.5% and results in an approximate increase to the annual bill of a TGI lower mainland Residential customer of $38 per year or approximately 3.6%.

6.1 Could Terasen please provide a break out of the impact of the capital structure going from 35 to 40 and the ROE going from 8.47% to 11% independently of each other?

Response:

The following chart provides a break out of the impacts of the capital structure and ROE changes independently of one another:

	Equity	ROE
Revenue Requirement Increase ($ Million)	$ 8.9	$ 31.4
Increase as % of Gross Margin	1.7%	5.9%
Residential Customer Annual Bill* Impact $	$ 7	$ 25
Residential Customer Annual Bill* Impact %	0.7%	2.4%

**Annual Bill Impact based on a Lower Mainland Residential Customer consuming 95 GJs per year*

The independent results cannot be added together to arrive at the combined impact as described in the response to BCUC IR 1.3.4 because of the compounding impact that the combined change has on the earned return as well as a difference in the forecast long term debt assumptions. The impacts of combined changes and the equity alone scenario assume that approximately $100 million in forecast new long term debt issuances will not be required.

7.0 Reference: BCUC IR# 1.7.1

The current AAM assumes a stable equity risk premium between the GCB yield and the allowed ROE. By extension, assuming a stable equity risk premium would imply that the corporate credit spread is stable.

7.1 Please provide the Credit Spread history month by month, if possible, relative to the long GCB yield and the allowed ROE for TGI since the inception of AAM.

Response:

Please see the data in the following table, which has been provided by Scotia Capital. The data was available starting September 1996. The TGI indicative new issue spread included in the table is a Scotia Capital indicative new issue spread at a single point in time for the month noted. Scotia does not keep a database of what was the then current long Government of Canada Bond yield corresponding to the date of the indicative new issue, but instead have provided a constant maturity long GCB yield as of the corresponding date of each indicative new issue spread. The ROE for TGI is the annual allowed ROE for the corresponding months.

	Long GCB Yield	30 yr Spread	Allowed ROE
Sep-96	7.88%	0.55%	11.00%
Oct-96	7.17%	0.60%	11.00%
Nov-96	6.73%	0.60%	11.00%
Dec-96	7.17%	0.65%	11.00%
Jan-97	7.39%	0.65%	10.25%
Feb-97	7.08%	0.65%	10.25%
Mar-97	7.37%	0.65%	10.25%
Apr-97	7.37%	0.60%	10.25%
May-97	7.10%	0.60%	10.25%
Jun-97	6.89%	0.54%	10.25%
Jul-97	6.33%	0.48%	10.25%
Aug-97	6.62%	0.48%	10.25%
Sep-97	6.27%	0.50%	10.25%
Oct-97	6.12%	0.57%	10.25%
Nov-97	5.95%	0.68%	10.25%
Dec-97	5.98%	0.68%	10.25%

	Long GCB Yield	30 yr Spread	Allowed ROE
Jan-98	5.74%	0.75%	10.00%
Feb-98	5.82%	0.80%	10.00%
Mar-98	5.72%	0.70%	10.00%
Apr-98	5.73%	0.65%	10.00%
May-98	5.62%	0.65%	10.00%
Jun-98	5.51%	0.68%	10.00%
Jul-98	5.52%	0.72%	10.00%
Aug-98	5.72%	0.95%	10.00%
Sep-98	5.32%	1.25%	10.00%
Oct-98	5.44%	1.40%	10.00%
Nov-98	5.45%	1.04%	10.00%
Dec-98	5.21%	1.10%	10.00%
Jan-99	5.24%	1.10%	9.25%
Feb-99	5.36%	1.00%	9.25%
Mar-99	5.43%	1.00%	9.25%
Apr-99	5.48%	0.98%	9.25%
May-99	5.53%	1.00%	9.25%
Jun-99	5.72%	1.12%	9.25%
Jul-99	5.75%	1.15%	9.25%
Aug-99	5.85%	1.15%	9.25%
Sep-99	5.83%	1.10%	9.25%
Oct-99	6.43%	1.09%	9.25%
Nov-99	6.12%	1.03%	9.25%
Dec-99	6.24%	1.00%	9.25%
Jan-00	6.28%	0.95%	9.50%
Feb-00	5.88%	1.20%	9.50%
Mar-00	5.76%	1.25%	9.50%
Apr-00	5.93%	1.25%	9.50%
May-00	5.88%	1.43%	9.50%
Jun-00	5.54%	1.45%	9.50%
Jul-00	5.53%	1.33%	9.50%
Aug-00	5.51%	1.33%	9.50%
Sep-00	5.65%	1.30%	9.50%

	Long GCB Yield	30 yr Spread	Allowed ROE
Oct-00	5.65%	1.43%	9.50%
Nov-00	5.55%	1.55%	9.50%
Dec-00	5.54%	1.50%	9.50%
Jan-01	5.74%	1.47%	9.25%
Feb-01	5.73%	1.45%	9.25%
Mar-01	5.79%	1.47%	9.25%
Apr-01	6.02%	1.33%	9.25%
May-01	6.06%	1.45%	9.25%
Jun-01	6.02%	1.55%	9.25%
Jul-01	5.88%	1.60%	9.25%
Aug-01	5.70%	1.60%	9.25%
Sep-01	5.80%	1.80%	9.25%
Oct-01	5.68%	1.70%	9.25%
Nov-01	5.48%	1.65%	9.25%
Dec-01	5.65%	1.60%	9.25%
Jan-02	5.71%	1.55%	9.13%
Feb-02	5.63%	1.60%	9.13%
Mar-02	5.98%	1.45%	9.13%
Apr-02	5.90%	1.38%	9.13%
May-02	5.79%	1.35%	9.13%
Jun-02	5.81%	1.40%	9.13%
Jul-02	5.74%	1.55%	9.13%
Aug-02	5.51%	1.50%	9.13%
Sep-02	5.44%	1.50%	9.13%
Oct-02	5.70%	1.65%	9.13%
Nov-02	5.57%	1.70%	9.13%
Dec-02	5.37%	1.70%	9.13%
Jan-03	5.46%	1.70%	9.42%
Feb-03	5.50%	1.70%	9.42%
Mar-03	5.58%	1.85%	9.42%
Apr-03	5.53%	1.80%	9.42%
May-03	5.00%	1.75%	9.42%
Jun-03	5.01%	1.70%	9.42%

	Long GCB Yield	30 yr Spread	Allowed ROE
Jul-03	5.38%	1.65%	9.42%
Aug-03	5.35%	1.65%	9.42%
Sep-03	5.16%	1.55%	9.42%
Oct-03	5.34%	1.50%	9.42%
Nov-03	5.33%	1.28%	9.42%
Dec-03	5.19%	1.22%	9.42%
Jan-04	5.19%	1.10%	9.15%
Feb-04	5.13%	1.18%	9.15%
Mar-04	5.04%	1.28%	9.15%
Apr-04	5.27%	1.27%	9.15%
May-04	5.31%	1.30%	9.15%
Jun-04	5.41%	1.33%	9.15%
Jul-04	5.25%	1.30%	9.15%
Aug-04	5.14%	1.25%	9.15%
Sep-04	5.03%	1.25%	9.15%
Oct-04	4.95%	1.25%	9.15%
Nov-04	4.99%	1.25%	9.15%
Dec-04	4.86%	1.25%	9.15%
Jan-05	4.71%	1.20%	9.03%
Feb-05	4.76%	1.18%	9.03%
Mar-05	4.85%	1.16%	9.03%
Apr-05	4.60%	1.28%	9.03%
May-05	4.41%	1.25%	9.03%
Jun-05	4.22%	1.22%	9.03%
Jul-05	4.28%	1.13%	9.03%
Aug-05	4.15%	1.14%	9.03%
Sep-05	4.25%	1.16%	9.03%
Oct-05	4.36%	1.25%	9.03%
Nov-05	4.15%	1.26%	9.03%
Dec-05	4.11%	1.26%	9.03%
Jan-06	4.25%	1.27%	8.80%
Feb-06	4.18%	1.29%	8.80%
Mar-06	4.18%	1.29%	8.80%

	Long GCB Yield	30 yr Spread	Allowed ROE
Apr-06	4.49%	1.29%	8.80%
May-06	4.35%	1.27%	8.80%
Jun-06	4.68%	1.45%	8.80%
Jul-06	4.37%	1.50%	8.80%
Aug-06	4.25%	1.45%	8.80%
Sep-06	4.01%	1.34%	8.80%
Oct-06	4.13%	1.28%	8.80%
Nov-06	4.04%	1.27%	8.80%
Dec-06	4.12%	1.28%	8.80%
Jan-07	4.26%	1.25%	8.37%
Feb-07	4.10%	1.25%	8.37%
Mar-07	4.21%	1.20%	8.37%
Apr-07	4.19%	1.20%	8.37%
May-07	4.39%	1.15%	8.37%
Jun-07	4.54%	1.15%	8.37%
Jul-07	4.48%	1.30%	8.37%
Aug-07	4.40%	1.33%	8.37%
Sep-07	4.48%	1.43%	8.37%
Oct-07	4.36%	1.35%	8.37%
Nov-07	4.14%	1.50%	8.37%
Dec-07	4.18%	1.45%	8.37%
Jan-08	4.15%	1.68%	8.62%
Feb-08	4.25%	1.55%	8.62%
Mar-08	3.93%	1.60%	8.62%
Apr-08	4.20%	1.65%	8.62%
May-08	4.09%	1.60%	8.62%
Jun-08	4.08%	1.65%	8.62%
Jul-08	4.13%	1.95%	8.62%
Aug-08	4.06%	1.95%	8.62%
Sep-08	4.02%	2.50%	8.62%
Oct-08	4.13%	3.30%	8.62%
Nov-08	4.07%	3.15%	8.62%
Dec-08	3.77%	3.60%	8.62%

	Long GCB Yield	**30 yr Spread**	**Allowed ROE**
Jan-09	3.71%	3.50%	8.47%
Feb-09	3.58%	2.85%	8.47%
Mar-09	3.59%	2.85%	8.47%
Apr-09	3.76%	2.55%	8.47%
May-09	3.98%	2.20%	8.47%
Jun-09	3.90%	1.80%	8.47%
Jul-09	3.86%	1.70%	8.47%

Source: Scotia Capital Inc.

8.0 Reference: BCUC IR# 1.10.2

Terasen Gas does not agree with the position that U.S. utilities having to implement social policy tools are more at risk than their Canadian counterparts in revenue recovery. In Terasen's view, U.S. utilities participating in income assistance programs face lower risk than their Canadian counterparts that do not have similar programs. Income assistance programs lower the overall bad debt that a utility experiences by shifting payment responsibility to the programs and reducing the number of customers who cannot afford to pay their bills. Canadian utilities, including Terasen Gas, that do not participate in income assistance programs transfer their budgeted bad debt responsibility to their rates. However bad debt above budgeted levels is borne by shareholders. Canadian utilities without access to similar social assistance programs therefore face more risk than comparable US utilities.

8.1 Please compare the bad debt experience of Terasen Gas and of the utilities for which Terasen has obtained low income assistance program information.

<u>Response:</u>

Terasen does not have the actual bad debt experience information of the US utilities for whom the low income assistance program information is available. The view expressed in the paragraph referenced above is one where individuals of limited means who receive assistance with their utility bills are less likely to default on those bills than those who do not have supplemental assistance. The inference in the original BCUC questions in this set were to the effect that Canadian utilities are somehow less risky because they do not have low income assistance programs when the opposite is more likely the case.

9.0 Reference: BCUC IR# 1.14.1

TGI employs multiple strategies to manage competitive risk including the use of hedging, rate design and cost containment.

9.1 Terasen has not applied to pass this perceived “future competitiveness” risk along to current customers nor for an account to carry the proceeds through until such time as the company may face realization of stranded cost risks. Does Terasen believe this would be a relevant cost for customers to bear and would such an arrangement reduce Terasen’s risks as outlined in response to the BCUC question?

Response:

As noted in the response to BCUC 1.14.1:

> *“Costs, both operating and capital related must be recovered in the short and long term. The fact that a regulator allows costs to be recovered in rates does not in and of itself eliminate the business risk though a disallowance of costs in the regulatory context crystallizes a loss. Ultimately customers must be willing to buy and pay for the service. If rates are not competitive either on a cost per unit energy basis or the product/service falls out of favour and customers leave the system, then costs, even though allowed in rates, can become unrecoverable in the long run.”*
>
> *“TGI employs multiple strategies to manage competitive risk including the use of hedging, rate design and cost containment.”*

The referenced statement was used to illustrate how TGI attempts to ensure it can maintain its customer base and stay competitive with alternatives. Terasen does pass the associated costs of these programs through to customers in rates but they do not guarantee competitiveness will be maintained, nor does an order to approve a deferral account guarantee the costs included in such an account will be recovered in the future. These are the longer term risks that the allowed ROE is meant to compensate for.

10.0 Reference: BCUC IR# 1.14.5

No. If some of the risk associated with the volatility of return on an investment in Stock A can be reduced by including Stock A in a well-diversified portfolio, then the observation that Stock A has greater volatility than Stock B does not necessarily indicate that Stock A is more risky than Stock B. However, the average investor associates risk with the concept of uncertainty about an expected outcome. For such an investor, the observation that the return on Stock A is more volatile than the return on Stock B is strongly supportive of the conclusion that Stock A is more risky than Stock B.

10.1 Why would inclusion in a diversified portfolio reduce the risk of Stock A? Would not the risk of Stock A be inherent to Stock A and diversification only mitigate risk of a number of holdings?

Response:

Inclusion in a diversified portfolio would reduce the risk of Stock A if investors are not concerned only with the volatility of Stock A itself, but also with the effect of Stock A on the variability of their portfolio return.

10.2 Why would volatility of return necessarily be more risky? Would it not be true that the certainty, security & predictability of the return would define risk rather than strictly the volatility?

Response:

Volatile stocks are frequently considered to be more risky because volatility is a reasonable measure of the uncertainty of a stock's return. Risk is frequently defined by *uncertainty* or *unpredictability* of return. As noted, volatility is frequently considered to be a reasonable measure of the uncertainty or unpredictability of a stock's return.

10.3 Would it also not be true that more volatile returns could frequently, in the market, be less certain, secure and predicable?

Response:

Volatile returns are frequently less certain and predictable.

10.4 Would it also not be true that cyclical returns caused by economic cycles may be reasonably anticipated and could be inherently more certain and secure than a less volatile return and that the real risk issues go to the root of the underlying sustainability of the average return?

Response:

Cyclical returns caused by economic cycles cannot be reasonably anticipated because: (1) economic cycles themselves cannot be reasonably anticipated; and (2) the effect of economic cycles on stock returns varies from one cycle to another.

11.0 Reference: BCUC IR# 1.17.2.1

As discussed in the response to 17.2 above and Section 5.2 of the Application, the new risks experienced by TGI are also felt by TGVI and TGW. The BC Hydro RIB rates are postage stamp rates that apply equally in each of the Terasen Utilities service areas and TGVI and TGW rates continue to be substantially higher than those of TGI. In the case of TGW, the Commission opined on the appropriate utility specific risk premium in April 2009 and TGW is not seeking reconsideration of that determination. For TGVI the current rate setting mechanism in place sets rates for certain customer classes with reference to electricity rates and they have moved in lock step with changes to electricity rates so the competitiveness level is essentially unchanged from where it was before the RIB rates were introduced. While the Revenue Deficiency Deferral Account is expected to be reduced to zero in 2009, TGVI does not recover its full cost of service without ongoing Royalty subsidization of its cost of gas for sales customers. The Royalty subsidy will be removed by the end of 2011 at which time there will be substantial upward pressure on rates which would be expected to exceed those of the BC Hydro RIB rates.

11.1 Does Terasen agree that TGVI is more likely to be positively impacted by BC Hydro’s RIB rate that TGI because of the proportion of electric space & water heating on Vancouver Island as opposed to the TGI region, despite the fact that the RIB rates are postage stamp in all regions?

Response:

The Terasen Utilities are aware of the evidence filed in the BC Hydro RIB proceeding that a there is a higher prevalence of electric space heating on Vancouver Island than in other regions in BC Hydro’s service territory. The RIB Step 2 rate is likely to drive more electricity conservation for BC Hydro on Vancouver Island particularly among customers that use electricity for space heating. However, the Terasen Utilities expect very little impact of the RIB rate structure on gas throughput from existing electric space heating customers because the cost of retrofitting a dwelling to use gas is a significant barrier to fuel switching. The RIB rate structure has more potential to impact the new construction market where the gas share of the market may improve modestly. The other factors that influence developers and consumers away from using gas will still exist on Vancouver Island as much as they do in TGI’s service territory. These include the extra upfront capital and maintenance costs of a gas heating system and the potential for future carbon tax increases, among other things. TGVI believes developers, in particular, will continue to see the extra costs of installing ducting and a central furnace in a new dwelling as an expense they may not be able to recover in their selling price. There is still a small amount of potential on Vancouver Island for conversions to natural gas from fuels other than electricity such as fuel oil and propane. In these cases the dwelling already has ductwork and the RIB rate structure may serve to encourage these types of conversions to adopt natural gas rather than electricity when a decision is made to replace a furnace.

11.2 Are the TGVI rates that are moving in lock step with changes to electricity rates moving in relation to the average electricity rates or to the Tier 2 RIB rate?

Response:

TGVI is using an averaged electricity rate for its rate adjustments that are tied to electricity rates. The description in the question of gas rates moving in lock step with changes in electricity rates is not entirely accurate. Rates have been set in comparison to alternative fuels, including electricity rates using the Soft Cap mechanism. The use of an averaged electricity rate as the benchmark for rate setting maintains stable rates and provides continuity with past rate setting practice. Further TGVI does not believe that the RIB Step 2 rate is the relevant comparator for natural gas consumption in all circumstances and so has not adopted the higher electricity rate for use in its rate setting process going forward. TGVI believes that another consideration for not using the RIB Step 2 rate as the benchmark for setting gas rates is that the any beneficial effect of the marginal price signal from a higher gas-electricity rate differential would be lost if gas rates were linked to the RIB Step 2 rate.

11.3 The royalty subsidization issue is presumably a constant independent of whether or not the Revenue Deficiency Deferral Account is reduced to zero, is that not correct? All other things being equal would not the elimination of the Revenue Deficiency as opposed to its continuation reduce one of the risks that TGVI previously had to deal with?

Response:

The royalty revenues from the Province continue to the end of 2011 and are independent of the balance in the RDDA.

TGVI’s revenues have exceeded its combined cost of service (excluding the costs associated with re-payment of the RDDA balance) and cost of gas since 2003, but by a margin smaller than the amount of the royalty revenues. TGVI has been re-paying the accumulated revenue deficiency in the RDDA since 2003. TGVI expects the RDDA to be repaid in 2009.

In its 2010-2011 Revenue Requirements and Rate Design Application TGVI is proposing the continuation of current 2009 rates in 2010-2011 under a rate freeze. On this basis rates would collect more than the cost of service and TGVI is seeking to build a surplus to amortize commencing in 2012 with the intention of mitigating the rate impact arising from the loss of the royalty revenues.

TGVI's evidence in this Application regarding the risks it faces has included the expectation that the accumulated RDDA deficit would be eliminated in and around 2009. Therefore the elimination of the RDDA deficit does not change TGVI's riskiness. The rate impact of the elimination of the royalty revenue is a much larger contributor to TGVI's riskiness. Likewise, TGVI has included the loss of the royalty revenue in its assessment of the riskiness of the Company and the contribution of that factor to TGVI's assessment of its risk does not change with the elimination of the accumulated RDDA deficiency.

12.0 Reference: BCUC IR# 1.19.1.3

Yes, TGI has included changes in housing mix and also changes in the conservation culture as a business risk component. Both of those factors influence the demand for natural gas, both are prevalent throughout the province, and therefore those factors add to the risk of all the Terasen Utilities. The business risk of TGVI and TGW relative to that of TGI is still appropriate, and do not require re-evaluation at this time.

12.1 The CEC understands that TGI is looking for BCUC approval to provide alternative energy solutions as part of a utility service offering. Would such approval if it were to come potentially mitigate the housing mix and conservation culture risks as Terasen sees them?

Response:

It has the potential to both mitigate these risks while at the same time introducing new challenges and risks for the business. However, the do nothing approach which sees the company's base business diminish over time is not a viable option. Businesses must take risk in their business operations, but in so doing they also have the expectation of earning an appropriate return for taking such risks.

13.0 Reference: BCUC IR# 1.19.1.4

In TGVI's case, it was originally envisioned that gas fired electric generating facilities constructed in addition to the demand of the pulp mills on island would provide a stable underpinning for the growth and development of the natural gas distribution business in TGVI's service territory. Only one co-gen facility was ever constructed and the Vancouver Island Gas Joint Venture group of pulp mills' demand has decreased down to less than 25% of the contract demand levels at the start of the decade. This has delayed the development of TGVI into a strong viable LDC in the absence of continued government support and continues to warrant a higher return than the benchmark.

13.1 The CEC understands that Terasen is planning to propose an amalgamation of TGVI and TGW with TGI. Would such an amalgamation eliminate the need to add a risk premium for TGVI and TGW or would Terasen argue to increase the ROE for the amalgamated entity?

Response:

Terasen is considering amalgamating the three gas utilities in the future into one larger entity similar to that of BC Hydro, the primary competitor. Such an application or proposal has not taken place and this proceeding is to establish the returns of the utilities as they are currently constituted.

In the event an amalgamation goes forward Terasen at that time would consider the appropriate ROE and capital structure for the amalgamated entity. At this time, Terasen would envision that the capital structure and ROE of the entities that exist at the time of the amalgamation would be blended to form the capital structure and ROE of the newly amalgamated entity, on a weighted average basis, similar to the way it was done when TGI amalgamated with Terasen Gas (Squamish) Inc.

13.2 Would an amalgamation enhance Terasen's ability to compete on Vancouver Island?

Response:

Terasen expects that an amalgamation resulting in harmonized rates across the province would enhance its competitive position for most customer rate classes on Vancouver Island while modestly degrading its competitive position for most customer classes on the mainland. For this reason a blended capital structure and ROE would be appropriate.

14.0 Reference: BCUC IR# 1.20.1

There is no deferral account for variations between forecast and actual thoughput for the industrial customer groups of TGI. There is a deferral account for variations between forecast and actual volumes due to use rate variations for Residential and Commercial customer classes, but there is no deferral account for changes in volumes resulting from variations in the forecasted number of customers.

14.1 Has Terasen applied for such deferral accounts as to mitigate these two risks? Does Terasen believe it would help mitigate these risks to have them handled in deferral accounts? Does Terasen believe that handling such risks in deferral accounts would mitigate the Terasen's perceived need to increase ROE at all and or to any degree?

Response:

Terasen has not applied for such deferral accounts, with the exception of the Ft. Nelson division of TGI which was facing uncertainty over the timing of a mill shut down of the second of its two former industrial customers that would dramatically impact the overall throughput of the division.

As has been indicated in earlier responses, the volume related deferral accounts serve useful and practical purposes as they eliminate windfall gains and losses for the company and its customers. If weather and other factors that influence consumption could be more accurately predicted then there would be no need for such accounts. Because that is not possible, in the absence of these deferrals the Company would be incented to be conservative on its load forecasts to provide itself with protection for reduced loads resulting in higher rates, and customers would argue for higher throughput forecasts to reduce their rates. The deferral accounts eliminate the biases of either side.

In the long run, the existing accounts do not reduce risk if the product is not competitive and demand falls.

Including deferral accounts for the items identified in the question would modestly dampen earnings volatility related but would not eliminate the need to set a fair return in this proceeding.

15.0 Reference: BCUC IR# 21.4

	1999 Actual	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Proposed
Category A												
Mains	5.7	5.9	4.6	4.6	4.2	5.3	7.4	8.1	8.1	11.0	8.9	8.3
Services	10.4	9.3	8.4	9.6	10.1	13.3	14.6	16.4	17.1	18.0	15.0	13.8
New Meters & Meters Recalled	15.5	14.7	13.7	13.4	17.5	15.4	15.3	16.2	13.7	14.9	14.0	19.7
Total Category A	**31.6**	**29.9**	**26.7**	**27.6**	**31.8**	**34.0**	**37.3**	**40.7**	**38.9**	**43.9**	**37.9**	**41.8**
Category B												
Transmission Plant	10.6	9.2	8.6	10.6	11.4	7.1	5.6	8.7	5.1	13.3	11.3	12.2
Distribution Plant	12.8	19.0	8.9	10.4	13.8	11.0	10.2	9.7	10.4	8.1	8.7	8.4
Total Category B	**23.4**	**28.2**	**17.5**	**21.0**	**25.2**	**18.1**	**15.8**	**18.4**	**15.4**	**21.4**	**20.0**	**20.6**
Category C												
IT	17.5	17.8	18.6	13.9	10.3	7.3	10.6	7.8	4.2	10.5	16.0	18.0
Non-IT	10.0	12.6	9.3	10.1	13.1	10.9	12.0	16.6	14.7	14.2	14.9	16.8
Total Category C	**27.5**	**30.4**	**27.9**	**24.0**	**23.4**	**18.3**	**22.6**	**24.5**	**18.8**	**24.7**	**30.9**	**34.8**
Total Base Capital	**82.5**	**88.5**	**72.1**	**72.6**	**80.4**	**70.4**	**75.7**	**83.6**	**73.2**	**90.0**	**88.8**	**97.2**
Figures exclude AFUDC and Capitalized Overheads												
CPCN	0.7	6.4	3.6	4.1	17.2	5.4	4.5	5.5	18.2	14.6	33.2	50.7

15.1 Could Terasen please provide the Proposed capital expenditures for 2011 as well?

<u>Response:</u>

Below is a revised summary to include the 2011 proposed capital expenditures.

TGI Capital Expenditures ($ millions)

	1999 Actual	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Proposed	2011 Proposed
Category A													
Mains	5.7	5.9	4.6	4.6	4.2	5.3	7.4	8.1	8.1	11.0	8.9	8.3	8.8
Services	10.4	9.3	8.4	9.6	10.1	13.3	14.6	16.4	17.1	18.0	15.0	13.8	15.1
New Meters & Meters Recalled	15.5	14.7	13.7	13.4	17.5	15.4	15.3	16.2	13.7	14.9	14.0	19.7	20.7
Total Category A	**31.6**	**29.9**	**26.7**	**27.6**	**31.8**	**34.0**	**37.3**	**40.7**	**38.9**	**43.9**	**37.9**	**41.8**	**44.6**
Category B													
Transmission Plant	10.6	9.2	8.6	10.6	11.4	7.1	5.6	8.7	5.1	13.3	11.3	12.2	25.2
Distribution Plant	12.8	19.0	8.9	10.4	13.8	11.0	10.2	9.7	10.4	8.1	8.7	8.4	6.8
Total Category B	**23.4**	**28.2**	**17.5**	**21.0**	**25.2**	**18.1**	**15.8**	**18.4**	**15.4**	**21.4**	**20.0**	**20.6**	**31.9**
Category C													
IT	17.5	17.8	18.6	13.9	10.3	7.3	10.6	7.8	4.2	10.5	16.0	18.0	18.0
Non-IT	10.0	12.6	9.3	10.1	13.1	10.9	12.0	16.6	14.7	14.2	14.9	16.8	16.7
Total Category C	**27.5**	**30.4**	**27.9**	**24.0**	**23.4**	**18.3**	**22.6**	**24.5**	**18.8**	**24.7**	**30.9**	**34.8**	**34.7**
Total Base Capital	**82.5**	**88.5**	**72.1**	**72.6**	**80.4**	**70.4**	**75.7**	**83.6**	**73.2**	**90.0**	**88.8**	**97.2**	**111.2**
Figures exclude AFUDC and Capitalized Overheads													
CPCN	0.7	6.4	3.6	4.1	17.2	5.4	4.5	5.5	18.2	14.6	33.2	50.7	58.3

Note: Expenditures in $millions

15.2 Are the major CPCN expenditure projected and proposed by Terasen increase or decrease Terasen's business risks?

Response:

As the Commission approval Certificate indicates, these projects if approved are in the "Public Convenience and Necessity". Major projects currently under construction and proposed include the Mt. Hayes LNG storage facility (TGVI), the South Fraser directional drill project, and the Customer Care Enhancement (CCE) project. The directional drill project enhances safety and reliability of the system in the event of a major seismic event.

The LNG facility reduces certain risks related to security of supply in the event of an upstream pipeline interruption and introduces new risks which must be and are being managed.

The CCE project will allow us to better serve our customers which should provide positive benefits for both the customers and the utility. The transition back to in-sourced service provision introduces risk especially during the transition period which must be planned for and managed. The risk management plan is an integral part of the project plan as it is for all major projects Terasen undertakes.

16.0 Reference: BCUC IR# 1.23.2.1.2

Although TGI agrees that the increased number of dwelling units assumptions appear reasonable, as per TGI's response to BCUC IR#1 Q23.2.1, the ongoing shift towards more multi-family dwellings in the housing mix will place downward pressure on throughput levels, not increase it.

16.1 Please confirm that this answer depends on the implicit assumption that Terasen either does not do anything to increase its capture rate for multi-family dwellings and or that whatever Terasen tries it is unsuccessful at achieving any improvement?

Response:

Terasen's response to BCUC IR1.23.2.1.2 was based on current estimated capture rates for multi-family dwellings, and therefore no assumptions regarding future increases in capture rates were made. Terasen does recognize that changes in capture rates for multi-family dwellings would impact the change in consumption levels as single family dwellings are replaced with multi-family dwellings. However, given the declining competitiveness of natural gas with respect to electricity, and also the public perception of natural gas as a fossil fuel which is contributing towards GHG emissions, improving upon current capture rates for multi-family dwellings will be challenging, and therefore the assumptions used in response to BCUC IR1.23.2.1 are reasonable.

16.2 Does Terasen plan to implement strategies to improve its capture rate?

Response:

Please see CEC IR# 1.36.4 and 1.36.5 for Terasen's undertakings to improve capture rates in the multi-family housing marketplace.

17.0 Reference: BCUC IR# 1.26.1

Please refer to Attachment 26.1 for the increases in total annual bill and percentage burner-tip for typical Lower Mainland residential (Rate Schedule 1), commercial (Rate Schedule 3), and industrial (Rate Schedule 5) customers as a result of the carbon tax in 2011 and 2013.

17.1 The CEC has not been able to find the Attachment 26.1 in the file downloaded with respect to these BCUC IR#1 questions, would it be possible to specifically provide the Attachment for us?

Response:

Attachment 26.1 provided in response to BCUC IR 1.26.1 is available on the BCUC proceeding website under Exhibit B-3-1. It is provided as Attachment 17.1 to this response for CEC ease of reference.

Attachment 17.1

TGI Lower Mainland Typical Annual Bills

	2009	2010	2011	2012	2013
Rate Schedule 1 (Residential) Customers					
Typical Annual Usage	**95**	**95**	**95**	**95**	**95**
Basic Charge per month	$11.84	$11.84	$11.84	$11.84	$11.84
Delivery Charge per GJ	$2.795	$2.795	$2.795	$2.795	$2.795
Midstream Charge per GJ	$1.015	$1.015	$1.015	$1.015	$1.015
Cost of Gas per GJ	$5.962	$5.962	$5.962	$5.962	$5.962
TGI Total Annual Bill	**$1,070**	**$1,070**	**$1,070**	**$1,070**	**$1,070**
Carbon Tax per GJ	**$0.7449**	**$0.9949**	**$1.2449**	**$1.4949**	**$1.7449**
Annual Carbon Tax Amount	**$71**	**$95**	**$118**	**$142**	**$166**
Total Annual Bill Inclusive of Carbon Tax	***$1,141***	***$1,165***	***$1,189***	***$1,212***	***$1,236***
Annual Bill Increases Due to Carbon Tax					
Annual Bill Increase per Year		**$24**	**$24**	**$24**	**$24**
Annual Percentage Increase		**2.08%**	**2.04%**	**2.00%**	**1.96%**

	2009	2010	2011	2012	2013
Rate Schedule 3 (Commercial) Customers					
Typical Annual Usage	**2,800**	**2,800**	**2,800**	**2,800**	**2,800**
Basic Charge per month	$132.52	$132.52	$132.52	$132.52	$132.52
Delivery Charge per GJ	$2.037	$2.037	$2.037	$2.037	$2.037
Midstream Charge per GJ	$0.809	$0.809	$0.809	$0.809	$0.809
Cost of Gas per GJ	$5.962	$5.962	$5.962	$5.962	$5.962
TGI Total Annual Bill	**$26,253**	**$26,253**	**$26,253**	**$26,253**	**$26,253**
Carbon Tax per GJ	**$0.7449**	**$0.9949**	**$1.2449**	**$1.4949**	**$1.7449**
Annual Carbon Tax Amount	**$2,086**	**$2,786**	**$3,486**	**$4,186**	**$4,886**
Total Annual Bill Inclusive of Carbon Tax	***$28,338***	***$29,038***	***$29,738***	***$30,438***	***$31,138***
Annual Bill Increases Due to Carbon Tax					
Annual Bill Increase per Year		**$700**	**$700**	**$700**	**$700**
Annual Percentage Increase		**2.47%**	**2.41%**	**2.35%**	**2.30%**

	2009	2010	2011	2012	2013
Rate Schedule 5 (Industrial) Customers					
Typical Annual Usage	**9,700**	**9,700**	**9,700**	**9,700**	**9,700**
Basic Charge per month	$587.00	$587.00	$587.00	$587.00	$587.00
Delivery Charge per GJ	$0.515	$0.515	$0.515	$0.515	$0.515
Demand Charge per GJ per Month	$14.655	$14.655	$14.655	$14.655	$14.655
Cost of Gas per GJ	$6.632	$6.632	$6.632	$6.632	$6.632
TGI Total Annual Bill	**$86,324**	**$86,324**	**$86,324**	**$86,324**	**$86,324**
Carbon Tax per GJ	**$0.7449**	**$0.9949**	**$1.2449**	**$1.4949**	**$1.7449**
Annual Carbon Tax Amount	**$7,226**	**$9,651**	**$12,076**	**$14,501**	**$16,926**
Total Annual Bill Inclusive of Carbon Tax	***$93,549***	***$95,974***	***$98,399***	***$100,824***	***$103,249***
Annual Bill Increases Due to Carbon Tax					
Annual Bill Increase per Year		**$2,425**	**$2,425**	**$2,425**	**$2,425**
Annual Percentage Increase		**2.59%**	**2.53%**	**2.46%**	**2.41%**

All rates are as at July 1st of each year, inclusive of applicable rate riders, and exclusive of any applicable taxes (except the Carbon Tax).
All delivery and commodity rates are held constant at current rates as at July 2009.