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October 30, 2008

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. - Fort Nelson Service Area ("TG Fort Nelson")

2009 Revenue Requirements Application (the "Application") and the Amended October 30, 2008 Application (the "Amended Application")

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

On September 4, 2008, Terasen Gas filed the Application as referenced above. On October 30, 2008, TG Fort Nelson filed the Amendment to the Application.

In accordance with Commission Order No. G-153-08 setting out the Regulatory Timetable for the Application, TG Fort Nelson respectfully submits the attached response to BCUC IR No. 1. Please note that all of the responses to the IRs are based on and reflect the Amended Application.

If you have any questions related to this filing, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachments

1.0 Reference: Potential Future Consolidation with TGI

Exhibit B-1, Section 1.2, p. 2; Section 9, p. 32

"Future consideration of consolidation of the Fort Nelson Service area with the remainder of Terasen Gas for regulatory purposes would mitigate the wide variability in rates that can occur in Fort Nelson …"

Referencing also the residential rate examples on the Terasen web site at:
http://www.terasengas.com/Homes/Rates/LowerMainlandSquamish.htm
http://www.terasengas.com/Homes/Rates/FortNelson.htm
http://www.terasengas.com/Homes/Rates/AllOtherAreasOfBC.htm

1.1 Referencing Table 9a on p. 32 of this Application and the Terasen web site, please confirm the cost in Fort Nelson at the existing 2008 rates would total $119.42 for 10 GJ.

Response:

It is important to note that with this Application, the Company is seeking an increase in its rates for delivery service to customers, effective January 1, 2009, to reflect changes in delivery margin. The cost of gas is treated as flow through in this Application, which means that change in tariff rates due to change in cost of gas would have no or nominal effect on total cost of service (excluding cost of gas).

When the Application was prepared, the Company utilized the $8.462 per GJ average cost of natural gas as shown in column 8, line 4 of Table 9a on page 32 of the Application, which was the approved gas cost recovery charge as at April 1, 2008. As can be seen from the table below, based on the approved gas cost recovery charge of $10.151 as at July 1, 2008, would cost $119.42 for 10 GJ. However, based on existing approved rates, as at October 1, 2008, the total cost for 10 GJ would be $98.68. As discussed in the cover letter accompanying the filing of this filing, the Company has amended its Application to reflect gas costs based on the approved rates effective October 1, 2008.

Effective Date	Approved Gas Cost Recovery Charge (in $/GJ)	Reference	Total Bill [1] (in $) @ 2008 existing rates
April 1, 2008	8.462	Order No. G-27-08 / G-39-08 & Table 9a, page 32 of the application	$102.53
July 1, 2008	10.151	Order No. G-95-08 & Figure 9, page 32 of the application	$119.42
October 1, 2008	8.078	Order No. G-128-08 & Terasen Gas Website	$98.68

[1] *Residential bill based on consumption of 10 GJ. Does not include applicable taxes.*

1.2 Please confirm the total cost for 10 GJ, at the July 1, 2008 rates, in Vancouver/Squamish and in All Other Areas of BC would be $149.47 and $149.24 respectively.

Response:

It is confirmed that the total cost for 10 GJ, at July 1, 2008 rates, in Vancouver/Squamish and in all other areas of BC is $149.47 and $149.24. This does not include applicable taxes.

1.3 Please comment on how a 25% increase the increase in rates that would occur for Fort Nelson on consolidation would be beneficial for the Fort Nelson residential customers.

Response:

The Company is not proposing to consolidate the Fort Nelson service area with the rest of TGI with this Application. The context of the quote referenced is the annual margin change in the Fort Nelson service area in 2008 and 2009 resulting in large part from reductions in industrial demand. The demand reductions have resulted in significant "variability" or volatility in rates in Fort Nelson. At some time in the future, the Company might consider consolidation as way to potentially address this variability.

1.4 Please provide the increase to Fort Nelson residential customers should the remaining Rate 25 customer cease to purchase transportation service.

Response:

In the event customers served under Rate Schedule 25 cease to purchase transportation service or use natural gas for space heating needs, Fort Nelson sales customers (customers served by Rate Schedules 1, 2.1 and 2.2) would see an additional increase of 4..3% (total increase of 7.3%) on the total annual bill, over and above the proposed rates included in the Application dated September 4, 2008. Please see the response to BCUC IR 1.8.2 for a discussion of the changes to the Industrial demand forecast proposed in the Amended Application.

2.0 Reference: Residential Average Consumption

Exhibit B-1, Section 1.5, p. 5; Section 3.4, p. 14

"Per residential customer at the average forecast annual consumption of 140 GJ."

Table 3.4 references 140.3 GJ for use in subsequent calculations.

Referencing the revised Third Quarter 2008 Gas Cost Report filed September 9, 2008, p. 2: "residential customer with an average annual consumption of 160 GJ."

2.1 Please comment on the 14.3% difference in the average consumption rates referenced above.

Response:

The residential customer average forecast annual consumption of 140 GJ, used in the TGI Fort Nelson 2009 Revenue Requirements Application, dated September 4, 2008, is based on currently available forecast and historical information.

The TGI Fort Nelson 2008 Third Quarter Gas Cost Report, dated September 4, 2008, and the TGI Fort Nelson 2008 Revised Third Quarter Gas Cost Report, dated September 9, 2008, utilized a residential customer average forecast annual consumption of 160 GJ in the bill impact calculations included within those submissions. The Company utilized 160 GJ as the average annual consumption figure in the bill impact schedules included within the 2008 Third Quarter Gas Cost Report and the 2008 Revised Third Quarter Gas Cost Report, in order to provide the appropriate level of consistency and comparability to the bill impact calculations included within the 2008 Second Quarter Gas Cost Report and the 2008 First Quarter Gas Cost Report, as well as prior year's reports. This consumption rate was used only for the purposes of the bill impact analysis. The demand forecasts included in the Quarterly Gas Cost Reports for 2008 were based on the approved consumption rates and demand forecasts included in the approved 2008 revenue requirements.

Going forward, the Company will utilize the revised average forecast annual consumption amounts for the bill impact calculations and customer communications for each of the various customer rate classes based upon the forecast information presented within the 2009 Revenue Requirements Application. Thus, bill impact calculations required as part of the TGI Fort Nelson 2008 Fourth Quarter Gas Cost Report will utilize the average forecast annual consumption amounts included in this Application.

2.2 If the September 9, 2008 filing provides more up-to-date volume forecast information, please provide revised schedules for the revenue requirement in this application.

Response:

The Company, in its Amended Application dated October 30, 2008, has provided revised volume forecast information pertaining to customers served under Rate Schedule 25 based on the recent announcement of the indefinite closure of Canfor's Tackama Plywood Mill. In the Amended Application, the Company has also provided revised financial schedules.

3.0 Reference: Forecast Methodology

Exhibit B-1, Section 3.1, p. 10

3.1 Please explain whether services to multiple family dwellings are provided under Rate Classes 2.1 and 2.2.

Response:

Multiple family dwellings could be provided service under the Rate 1, Rate 2.1, or Rate 2.2 customer classes. If the multiple family dwelling has individually metered units, then each of the units would become Rate 1 customers. If a single meter serves all of the units within a particular multiple family dwelling, then that dwelling would become a Rate 2.1 customer if their consumption was expected to be less than 6,000 GJ per year or a Rate 2.2 customer if their consumption was expected to be greater than 6,000 GJ per year.

3.2 If so, what proportion of the accounts in each of those rate classes are for multiple family dwellings?

Response:

Through reviewing a list of Rate 2.1 and Rate 2.2 customers, Terasen estimates there are 14 multiple family dwellings in the Rate 2.1 customer class, and 3 multiple family dwellings in the Rate 2.2 customer class. These figures represent 3% and 11% of all Rate 2.1 and Rate 2.2 customers respectively.

Note that housing type is not a variable that Terasen has tracked historically, and therefore the exact number of multiple family dwellings in each of the rate classes is not known. Given the relatively small size of TG Fort Nelson, a manual review of the customers in each of the rate classes allowed for the above figures to be estimated.

4.0 Reference: Underlying Assumptions

Exhibit B-1, Section 3.2, p. 11

"The latest population projection from BC Statistics shows an expected 1.7% increase in population for the TG Fort Nelson region from 2008 to 2009. This is lower than previous estimated growth rates (the expected growth from 2007 to 2008 was 3%)."

4.1 Please provide the BC Statistics report on which the forecast is based.

Response:

The population growth rate of 1.7% stated in Exhibit B-1, Section 3.2, p.11 is a typo, and should have been stated as 0.11%. The proper number has been used in all analysis. The BC Statistics report on which the forecast is based is the BC STATS Population Forecast, and following is the data for the Fort Nelson Local Health Area:

HA ID	Local Health Area	Year	Gender	Total	Growth
81	Fort Nelson	1986	T	5,472	
81	Fort Nelson	1987	T	5,322	-2.74%
81	Fort Nelson	1988	T	5,216	-1.99%
81	Fort Nelson	1989	T	5,008	-3.99%
81	Fort Nelson	1990	T	5,008	0.00%
81	Fort Nelson	1991	T	5,320	6.23%
81	Fort Nelson	1992	T	5,468	2.78%
81	Fort Nelson	1993	T	5,556	1.61%
81	Fort Nelson	1994	T	5,668	2.02%
81	Fort Nelson	1995	T	5,971	5.35%
81	Fort Nelson	1996	T	6,245	4.59%
81	Fort Nelson	1997	T	6,466	3.54%
81	Fort Nelson	1998	T	6,375	-1.41%
81	Fort Nelson	1999	T	6,288	-1.36%
81	Fort Nelson	2000	T	6,114	-2.77%
81	Fort Nelson	2001	T	6,104	-0.16%
81	Fort Nelson	2002	T	6,097	-0.11%
81	Fort Nelson	2003	T	6,179	1.34%
81	Fort Nelson	2004	T	6,455	4.47%
81	Fort Nelson	2005	T	6,567	1.74%
81	Fort Nelson	2006	T	6,572	0.08%
81	Fort Nelson	2007	T	6,433	-2.12%
81	Fort Nelson	2008	T	6,450	0.26%
81	Fort Nelson	2009	T	6,457	0.11%
81	Fort Nelson	2010	T	6,471	0.22%
81	Fort Nelson	2011	T	6,474	0.05%
81	Fort Nelson	2012	T	6,481	0.11%
81	Fort Nelson	2013	T	6,493	0.19%
81	Fort Nelson	2014	T	6,488	-0.08%
81	Fort Nelson	2015	T	6,483	-0.08%
81	Fort Nelson	2016	T	6,478	-0.08%
81	Fort Nelson	2017	T	6,479	0.02%
81	Fort Nelson	2018	T	6,486	0.11%
81	Fort Nelson	2019	T	6,505	0.29%
81	Fort Nelson	2020	T	6,538	0.51%
81	Fort Nelson	2021	T	6,576	0.58%
81	Fort Nelson	2022	T	6,614	0.58%
81	Fort Nelson	2023	T	6,651	0.56%
81	Fort Nelson	2024	T	6,690	0.59%
81	Fort Nelson	2025	T	6,732	0.63%
81	Fort Nelson	2026	T	6,790	0.86%
81	Fort Nelson	2027	T	6,850	0.88%
81	Fort Nelson	2028	T	6,914	0.93%
81	Fort Nelson	2029	T	6,987	1.06%
81	Fort Nelson	2030	T	7,064	1.10%
81	Fort Nelson	2031	T	7,136	1.02%
81	Fort Nelson	2032	T	7,213	1.08%
81	Fort Nelson	2033	T	7,291	1.08%
81	Fort Nelson	2034	T	7,369	1.07%
81	Fort Nelson	2035	T	7,441	0.98%
81	Fort Nelson	2036	T	7,513	0.97%

Please note that the column "HA ID" represents the Local Health Area ID, and that "T" in the Gender column represents the total population.

4.2 Please show how the BC Statistics estimates were incorporated into the forecast growth rates.

Response:

From the above population estimates, the growth rates for 2007 through 2009 translate into an estimated decline in population of 39 in 2007 followed by a projected increase in population of 17 in 2008 and 7 in 2009. Given that in 2007 TG Fort Nelson added 14 customers in spite of the population declining, the population growth estimates did not coincide with observed customer additions. Discussions with the Company's manager located in Fort Nelson, based on his knowledge of the area, led to the projection of 6 customer additions in 2008 and 12 customer additions in 2009.

5.0 Reference: Customer Additions/Loss

Exhibit B-1, Section 3.2, p. 11

"It is not unreasonable to assume customer additions will decline in the short term, but increase over the long term."

5.1 Referencing the above quote, and the 2,355 average number of customers for 2009 Forecast in Schedule 3, and the 2,386 year-end customers for 2009 Forecast in Table 3.3b, please explain if Terasen is projecting a loss of customers for 2010.

Response:

Terasen is not projecting a loss of customers in 2010. The above quote is discussing the number of customer additions declining, not the total number of customers. In relation to 2007, Terasen is expecting customer additions to decline over the short-term with 7 customer additions projected in 2008 and 12 projected in 2009.

5.2 Please comment on the current level of natural gas land sale and exploration activity in the Fort Nelson area, including in the Horn River Basin, and its potential impact on near future customer base and natural gas customer demand.

Response:

The province of British Columbia has sold over $2 Billion worth of land year to date September 2008 (more than double from 2007), with the majority of these sales being in the Horn River region. As per the Northern Rockies Regional District and Fort Nelson website (www.northernrockies.org), the town of Fort Nelson is only 60 miles from the Horn River Basin, and due to its close proximity is attractive to companies' intent on capitalizing on opportunities within the district. Although it is currently unknown how much of the estimated 35 trillion cubic meters of gas in the Horn River Basin is economically extractable, it is expected that enough will be extracted to make this play profitable for up to thirty years. Also, increased demand for light industrial lands has led to Fort Nelson working with provincial agencies towards the release, marketing, and development of close to 400 Hectares of land, which will more than triple the size of the light industrial land area. Fort Nelson has experienced economic downturn due to the U.S. sub-prime crisis and its effect on the forestry industry, which is also a part of the economic makeup of the town. Overall, positive growth is projected for the town which should translate into increased demand for natural gas.

5.3 To what extent does and will Fort Nelson act as the regional supply and services centre for this exploration activity?

Response:

As discussed above in BCUC IR 1.5.2 above, positive impacts will be felt in the town as a result of the Horn River development, given that Fort Nelson is the closest town to the region. As exploration activity ramps up in the region, the town should see an increase in the amount of services and supply it would be providing to the various companies involved in the development.

5.4 In the BC Hydro 2008 Long Term Acquisition Plan proceeding, page 84 of Appendix N1 in Exhibit B-1-1 shows a peak electricity load in 2008 of 42.8 megawatts. Table 8 on page 17 of Exhibit B-1-7 in that proceeding shows a peak demand in 2009 under the Low Scenario of 47.9 MW, a year-over-year increase of 12 percent. Please discuss why gas consumption is expected to increase at a so much slower rate than electricity consumption.

Response:

As far as Terasen Gas is aware the primary driver of the forecast electricity load growth in the Fort Nelson area is related to new oil and gas developments such as in the Horn River Basin. Appendix N1 of BC Hydro's LTAP does not indicate exactly where in the region its load growth is expected to occur but it is the Company's understanding that, in general, these areas are some distance away from the Fort Nelson Service Area distribution grid. To the extent that the energy requirements at these oil and gas developments are served by electricity it will be BC Hydro providing service. On the other hand if the energy requirements were to be met with gas, the oil and gas developers would typically use their own facilities and equipment, and a portion of the gas stream coming from the developments. Notwithstanding the effects on gas sales within the municipality of Fort Nelson as described in BCUC IRs 1.5.2 and 1.5.3 above, the primary impacts on electric load growth in the region will occur in areas that are not served by Terasen Gas.

5.5 Please explain whether Terasen Gas provides service to the BC Hydro Fort Nelson generating station. If an Independent Power Producer were to build a gas-fired generator to sell power to BC Hydro, is it likely that Terasen Gas would provide service to the IPP?

Response:

Terasen Gas' distribution system actually crosses the BC Hydro Ft. Nelson generating station but Terasen Gas does not currently provide gas service to the generating station. BC Hydro receives gas directly from the Spectra Pipeline. However, Terasen Gas would provide service to the generating station and Terasen Gas believes that where it can demonstrate to the Commission that its rate is comparable to the cost to the alternatives, Terasen Gas should be the provider of distribution service.

Similarly, Terasen Gas believes that if a new Independent Power Producer ("IPP") were to build a gas-fired generator to sell power to BC Hydro, Terasen Gas would provide service to the IPP. Terasen Gas would either charge postage stamp rates, or would negotiate, as appropriate, bypass rates consistent with the Commission decision on bypass rates of December 11, 1987.

6.0 Reference: Customer Additions

Exhibit B-1, Section 3.3, p. 12

"Table 3.3a presents normalized actual values for 2005 through to 2007."

6.1 Please explain the normalization of customer additions referred to in the above statement, and as presented in Table 3.3a.

Response:

Customer additions are not normalized, so the statement above should have the word "normalized" removed from it. Additionally, the word "normal" in Table 3.3a should be changed to read "actual". Following is a revision of table 3.3a:

Table 3.3a – TG Fort Nelson Customer Additions (Year-End Net)

	2005 Actuals	2006 Actuals	2007 Actuals	2008 Decision	2008 Projection	2009 Forecast
Rate 1	26	3	7	12	6	9
Rate 2.1	19	9	6	5	3	3
Rate 2.2	0	1	1	0	-2	0
Rate 25	0	0	0	0	0	0
Total	**45**	**13**	**14**	**17**	**7**	**12**

"…new housing tends to be added by sub-division which can add a significant number of new customers in a given year, but may then impact the subsequent year. For 2009, customer additions are expected to moderate as the uncertainty associated with the forestry industry may cause a delay in home purchasing decisions."

6.2 Are there residential sub-division or commercial building projects, in progress within the TGFN service area, which are expected to be completed during 2009? If so, how many units (residential) or how much floor space (commercial) is going to be added to the service area?

Response:

There are no known commercial building projects in progress within the TGFN service area at this time. There are four subdivisions within the TGFN service area with vacant lots on them. One of those subdivisions, with approximately 12 vacant lots, began selling during the summer 2008, but has only sold one lot to date. The other three subdivisions have approximately 170 vacant lots on them, with 7 being sold to date. The largest subdivision, with approximately 120 lots on it, is owned by the Fort Nelson First Nations, and is expected to see construction begin on 9 of those in 2009. Through information discussions with the Fort Nelson First Nation, Terasen has learned housing is a priority for them in 2009.

7.0 Reference: Customer Additions

Exhibit B-1, Section 3.3, pp. 12-13

	2006N	2007N	2008D	2008P	2009F
Table 3.3b, p. 13: Year-End Customers	2,354	2,368	2,368	2,374	2,386

	2007AN	2008D	2008P	2009F
Schedule 3, p. 39: Average number of customers	2,340	2,341	2,372	2,355
Schedule 4.1, p. 40: Average number of customers	2,340	2,341		
Schedule 4.2, p. 41: Average number of customers			2,372	2,355
Table 7.3a, p. 29: Average number of customers		2,341		2,355
Table 7.3b, p. 30: Average number of customers			2,372	2,355

7.1 Please explain how the 2008 Projected Customers of 2,341 on p. 20 compares to the numbers on p. 13 in Table 3.3b.

Response:

The 2008 Projected Customers of 2,341 illustrated on p.29 are the projected average number of customers over the twelve months of 2008. Those figures were submitted as part of the 2008 Fort Nelson Revenue Requirement Application (Order Number 158-07). The figures illustrated on p.13 in Table 3.3b are year-end customers, not the average number of customers, which is why they differ.

7.2 Please explain how the average number of customers in Schedules 3, 4.1 and 4.2 and in Tables 7.3a and 7.3b compare to Table 3.3b.

Response:

The average number of customers in Schedules 3, 4.1 and 4.2 and in Tables 7.3a and 7.3b are not comparable to the figures illustrated in Table 3.3b. The figures in Table 3.3b are year-end values, whereas the other figures are an average of the twelve month-end values of the applicable year.

8.0 Reference: Energy Demand Forecast

Exhibit B-1, Section 3.5, p. 15

"Based on survey results from Canfor for the Tackama Mill, it is expected that in 2009, consumption will stabilize at levels similar to what is being experienced in 2008."

8.1 Referencing the energy demand for Rate 25 in Table 3.5.2 on p. 15, please confirm the 7.4% reduction from 2008 Projection to 2009 Forecast is the result of a partial year without the transmission service to the OSB plant.

Response:

It is confirmed the 7.4% reduction in energy demand from the 2008 projection to the 2009 forecast is the result of a partial year without the transportation service to the OSB plant.

8.2 Please clarify the actual/projected loads of each of the OSB and Tackama plants in 2008, and show how the forecast for 2009 was calculated.

Response:

The demand projections for 2008 and forecasts for 2009 are based upon demand data that was collected through customer surveys during Q2/Q3 2008. The results indicated that for 2008 the OSB Plant's expected demand was 17,000 GJ and Tackama's expected demand was 213,900 GJ. For 2009, the OSB Plant's expected demand was zero, due to the closure of the plant earlier this year and Tackama's expected demand was 213,900 GJ. Subsequent to the filing of the Application, Canfor has announced the indefinite closure of Tackama Plywood Mill. Subsequent to that news release, TG Fort Nelson contacted representatives of Canfor in an effort to better understand the expected demand for natural gas for the two mills in 2009.

When the PolarBoard OSB plant was in production, Canfor operated a wood fired energy system that provided residual space heat from the production process. Although the mill is not operational, there is still a need to heat the facilities in order to preserve integrity of equipment and fire control systems. In order to ensure adequate heating within its PolarBoard facility, Canfor has installed a number of natural gas space heaters throughout the building to provide the required heat. As a result, Canfor believes that consumption at the PolarBoard plant may possibly increase for the winter of 2008-09 as compared to previous winters. PolarBoard has provided TG Fort Nelson with a very high-level estimate of approximately 90,000 GJ for gas year 2008-2009, which Canfor admits it has little confidence with the estimate. The maximum consumption over past five years for PolarBoard plant has been 57,000 GJ. TG Fort Nelson has no confidence in the accuracy of this high-level demand estimate provided by Canfor. No estimate has been provided by Canfor for its Tackama facility.

For the purposes of the Amended Application, TG Fort Nelson has assumed that these two customers served by Rate Schedule 25 ("Transport customers") will remain on TG Fort Nelson's system in year 2009 and will consume 950 GJ per month (minimum bill volume equivalent) during the winter months and 10 GJ per day during the summer months (based on Canfor's estimate). TG Fort Nelson believes that this is a fair and reasonable assumption to make as both Canfor and TG Fort Nelson have very little confidence in the accuracy of Canfor's forecast for natural gas usage since this is the first time Canfor has had to heat their facilities in this manner. Any margin variations arising from the difference between forecast and actual deliveries would be captured through the RSAM account. Attachment A provides the revised forecast tables which were included in the September 4, 2008 application, based on the closure of two facilities by Canfor as discussed above.

9.0 Reference: Revenue and Margin Forecast

Exhibit B-1, Section 3.6, p. 16

9.1 Given the forecast figures, what are the expected Revenue/Cost ratios for TGFN customer groups for 2009?

Response:

Please refer to Attachment 9.1, which is the high-level cost of service review for 2009 forecast. The revenue to cost ratios from the preliminary high level cost of service review prepared using forecast 2009 customers and demand and the 2009 proposed rates, based on the September 4, 2008 filing is included below. The cost of service review assumes the Rate Schedule 25 customer consumes gas for the full year and have been assigned a proxy commodity cost of gas like that included in Rate Schedule 3 in order to form a reasonable basis for a determination of revenue to cost. The cost of service review shows the revenue to cost ratios, even after consideration of the September 4, 2008 proposed rate changes for 2009, are within the + or – 10% zone of reasonableness. The Company considers this zone of reasonableness for revenues to cost ratios is appropriate at this time for TG Fort Nelson.

Customer Class	Residential	Small Commercial	Large Commercial	Firm General
Rate Class	Rate 1	Rate 2.1	Rate 2.2	Rate 25
Proposed 2009 Rates Revenue to Cost Ratio	93%	103%	107%	106%

10.0 Reference: Revenue Stabilization Adjustment Mechanism "RSAM"

Exhibit B-1, Section 3.7, pp. 16-18

Commission Order G-17-04, dated February 5, 2004, granted approval for the implementation of the RSAM account. Table 3-7 references the projected balance to be $229,857.

Referencing the update to the January 30, 2008 revised response to BCUC IR 1 for the TGI Fort Nelson 2008 Revenue Requirement discussed the impact of the curtailment of the Rate 25 customers.

10.1 Please provide details by year of the RSAM account since 2004 and projected forward for the three year amortization period.

Response:

The details of the RSAM account from 2004 to projected 2008 and forecast 2009 through 2011 based on the forecast filed on September 4, 2008 can be found on Attachment 10.1a. The current year's amortization is equal to 1/3 of the prior year-end net balance (net of tax effect and recoveries).

The projected 2008 balance and amortization for 2009 through 2011, based on the Amended Application dated October 30, 2008 are shown in Attachment 10.1b.

10.2 Please comment on the potential impact to the RSAM in future years should there be a full curtailment of the remaining Rate 25 customer. Provide the dollar impact on future years.

Response:

Although production will now be ceasing at both Polar Board and Tackama, both facilities will be requiring gas for space heating to ensure pipes and equipment are not impaired from freezing. Please see response to BCUC IR 1.8.2 and the Amended Application dated October 30, 2008.

In response to this question from having a zero load from Rate 25 customers in 2009 and forward, the effect on the RSAM recovery is shown on Attachment 10.2. The effect on RSAM recovery based on the revised Rate 25 volumes as per the Amended Application dated October 30, 2008, is shown in Attachment 10.1b. The RSAM recovery is based on 1/3 of the prior year closing balance; so the change from the loss of the Rate 25 load would be to increase the Rate Rider recovery charge from remaining customers.

Year	With Rate 25 Transportation Service Volumes $ / GJ (Attachment 10.1.b)	Without Rate 25 Transportation Service Volumes (Attachment 10.2)
2009	$0.236 / GJ	$0.242 / GJ
2010	$0.156 / GJ	$0.160 / GJ
2011	$0.102 / GJ	$0.105 / GJ

11.0 Reference: Cost of Gas

Exhibit B-1, Section 4, p. 19

The gas cost recovery charge in this Application is $10.151 per GJ, approved by Commission Order G-95-08, dated June 13, 2008 and effective July 1, 2008.

11.1 Please explain the how this amount relates to the $8.462 average cost of natural gas in column 8, line 4 of Table 9a on p. 32 and to the $10.15 shown in on p. 33 in Figure 9.

Response:

Column 8, line 4 of Table 9a on page 32 of the application dated September 4, 2008 shows the approved gas cost recovery charge of $8.462 effective April 1, 2008. TG Fort Nelson revenue forecast was prepared using this approved cost of gas embedded in rates as at April 1, 2008. The cost of gas was not updated in the application as the revenue deficiency is related to margin cost recovery and the cost of gas is treated as a flow through item. See also response to BCUC IR 1.1.1.

In the Amended Application, the Company has used the approved gas cost of $8.078 per GJ, effective October 1, 2008.

11.2 Please explain how the $8.462 average cost of gas is calculated.

Response:

Please see response to BCUC IR 1.11.1.

11.3 Order G-128-08 approved a Gas Cost Recovery Charge of $8.078/GJ for Fort Nelson effective October 1, 2008. Please provide forms of Tables 9a and 9b based on $8.078/GJ, and explain how each cost of gas number that differs from this figure was calculated.

Response:

Please refer to the revised Tables 9a and 9b provided in the Attachment A of the Amended Application dated October 30, 2008.

11.4 Further to the reference on page 26 to gas used in line heaters, for projected 2008 and forecast 2009, what is the gas usage in quantity and cost for each of Company Use and Unaccounted-for Gas.

Response:

The table below provides the quantity and cost for the Company Use and UAF Gas for projected 2008 and forecast 2009.

		Projected 2008	Forecast 2009
Company Use	TJ	3.1	3.3
	$000	$ 24.5	$ 30.3
UAF Gas	TJ	3.5	9.3
	$000	$ 29.9	$ 86.1

Consistent with past practice, the forecast UAF percentage incorporated in annual rates is calculated as the five-year average of the most recent recorded results. The five-year average UAF calculated for use in the 2008 forecast included the 2002 recorded UAF of -3.63%, whereas the five-year average UAF calculated for use in the 2009 forecast is based on the 2003-2007 recorded UAF, therefore excluding the significant negative UAF recorded in 2002.

The response to BCUC IR 1.15.1 provides a table which shows the actual recorded UAF percentages since 1999 and the five-year average UAF percentage used in annual rates since 2005.

11.5 Please explain how the cost of each of Company Use and UAF gas is recovered in Fort Nelson rates.

Response:

The cost associated with the Company Use gas is treated as an operating and maintenance expense. UAF gas cost for sales customers (customers served by Rate Schedule 1, 2.1 and 2.2) is a part of gas cost recovery charge, which is embedded within tariff rates. The current gas cost recovery charge is $8.078 per GJ, approved by Commission Order No. G-128-08, dated September 11, 2008 and effective October 1, 2008. UAF gas cost for transport customers (customers served by Rate Schedule 25) is recovered through approved tariff rate.

12.0 Reference: Gas Cost Reconciliation Account ("GCRA")

Exhibit B-1, Section 4, p. 19

Order G-128-08 approved a Gas Cost Recovery Charge of $8.078/GJ for Fort Nelson effective October 1, 2008.

12.1 Please explain the impact of the change in gas cost to the substance of this application.

Response:

As mentioned in response to BCUC IR 1.1.1 and 1.11.1, the change in the Gas Cost Recovery Charge to utilize the rates effective October 1, 2008, has no material impact on the substance of this Application, as the Application deals with the requested increase in delivery margin and the cost of service, excluding the cost of gas.

As discussed in the response to BCUC IR 1.8.2, concurrent with the filing of these IR responses, the Company is filing an Amended Application to reflect the impact of the indefinite closure of Canfor's Tackama Plywood Mill in Fort Nelson expected to occur by the end of October 2008. Additionally, with the Amended Application, the Company is submitting the revised financial schedules based on the approved Gas Cost Recovery charge of $8.078, effective October 1, 2008.

12.2 Using a gas commodity cost of $8.078, what would be the impact on the Application and on the requested delivery charge increases?

Response:

Please refer to the response to BCUC IR 1.12.1.

12.3 Please compare the impact to the average residential customer of the reduction in gas commodity cost approved for October 1, 2008 and the increase as a result of this Application, including the RSAM rider.

Response:

As mentioned in the response to Information Request 12.1, the reduction in gas commodity cost approved for October 1, 2008 does not have any impact on the substance of this application and the Company's rate proposals for 2009. The proposed increase in the sales rate (including the RSAM rate rider increase) for residential customers as a result of the Amended Application dated October 30, 2008 is $0.767 per GJ, effective January 1, 2009. This includes average margin increase of $0.647/GJ (refer to Revised Schedule 4.1, line 36) and increase in RSAM recovery charge of $0.12/GJ (refer to Attachment A, Revised Table 3.7, line 15). Based on average annual consumption of 140 GJ, the margin change and the RSAM rider change results in an annual increase of approximately $107 for residential customers.

13.0 Reference: Capital Expenditures

Exhibit B-1, Section 7.1, p. 28

13.1 What is the status of the new piping, hydrogen sulphide monitoring, and gas flow shut off equipment installation?

Response:

Subsequent to the TG Fort Nelson Revenue Requirement filing, discussions with Spectra have confirmed that Spectra will upgrade the hydrogen sulphide monitoring and shut in equipment on its system, without cost to TG Fort Nelson. Consequently, the TG Fort Nelson installation will now only consist of pressure control and overpressure protection equipment and will exclude hydrogen sulphide monitoring or gas flow shut off equipment. This results in a reduction of anticipated capital expenditures in 2009 by $50,000. This reduction in capital expenditures in 2009 has been reflected in the Amended Application dated October 30, 2008. This is discussed further in the response to BCUC IR 1.13.3. The TG Fort Nelson installation is only in the design stage and no materials have been ordered.

13.2 Please explain why the Fort Nelson Odorizer Station needs to be upgraded, and outline the scope and cost of the work being done?

Response:

The Fort Nelson Odorizer Station is the future site of the equipment, which requires an upgrade to accommodate the new equipment. As mentioned in the Response to BCUC IR 1.13.1, ongoing discussions with Spectra have resulted in a scope reduction of the new installation at the Fort Nelson Odorizer Station, such that it will only consist of pressure control and overpressure protection equipment. This new equipment is required in order to ensure appropriate pressure control and overpressure protection of the Fort Nelson Lateral in the event that gas coming from the Spectra system is at a pressure higher than the maximum allowable operating pressure of the Fort Nelson Lateral. Additionally, the installation of this equipment will also allow for the replacement of the leaking transmission valve at the site. In order to accomplish this, two 114mm control valves will be installed in line as main and monitor. The preliminary cost estimate, which is included in the Amended Application, is described below. It should be noted that this estimate is $50,000 lower than the amount included in the original Application, reflecting the fact that the hydrogen sulphide monitoring and shut in equipment will now be paid for by Spectra:

- **Cost Estimate:**

Materials	$ 37,000
Civil: Building, Fencing	6,400
Fabrication & Install	22,000
Project Management	9,000
Engineering	9,000
Contingency (20%)	16,600
Total	**$ 100,000**

13.3 Please reconcile the costs of the Fort Nelson Odorizer Station upgrade, the overpressure protection project and the H2S monitoring and shutoff project to Table 7.1, showing the total cost of each project.

Response:

Project	2008	2009
Upgrade Ft Nelson Stn (Obsolete Filter)	25,000	-
Upgrade Muskwa Stn (Obsolete Filter)	10,000	-
Tackama Station TP_DP - Lights	2,000	-
Muskwa Station; Flame Safeguard System	10,000	-
Ft Nelson Odr Stn - Pressure Control	20,000	80,000
Measuring & Regulating Equipment	67,000	80,000

Due to the discussions mentioned in the response to BCUC IR 1.13.1 the installation of the pressure control and overpressure protection equipment at the Fort Nelson Odorizer Station will be deferred to 2009. It is now expected that approximately $20,000 will be incurred in 2008 for project management, design and procurement of materials while approximately $80,000 will be incurred in 2009.

13.4 If the response to the previous question does not fully explain the increase for 2009 in "Mains", please provide a full explanation.

Response:

The $28,000 increase to Mains from $31,000 in 2008 to $59,000 in 2009 iis primarily attributed to Main alterations for valve culverts. Many of the distribution valves in the Fort Nelson system were installed when the system was first built (pre 1980's) and are of a type that is prone to leaking. These valves have started leaking significantly and many are located in deep culverts that are difficult to work in. TG Fort Nelson plans to remove and replace these valves over a three year period with either new valves or piping if a valve is no longer required at the specific site.

13.5 What was the result of discussions between Spectra with regards to the installation of devices on their system to accomplish the same objective?

Response:

Discussions during August and September of this year with Spectra have confirmed that Spectra will upgrade the monitoring and shut in equipment on their mainline, as described in the Response to BCUC IR 1.13.1. With appropriate protocols and validation of reaction time TG Fort Nelson anticipates this will be sufficient to address the concerns regarding hydrogen sulphide monitoring and shut in on the TG Fort Nelson system.

13.6 What are the contractual or government regulations with respect to the amount of hydrogen sulphide permitted in the natural gas being delivered by Spectra to Terasen?

Response:

The current contract with Spectra limits H2S content to no more than 6 mg/m3 or 4.2 ppm H2S.

13.7 What levels of H2S in gas delivered to the distribution system are considered hazardous? What safety or other problems result from the presence of such gas? On what occasions in the recent past has gas with such H2S content been delivered to the Terasen Gas system?

Response:

H2S is considered hazardous at levels of 20 – 50 ppm where symptoms such as throat irritation and stinging eyes begin to occur. Prolonged exposure can cause coughing, hoarseness, shortness of breath, and runny nose. At levels of 100 – 150 ppm sense of smell is blocked ("Olfactory Fatigue"). Prolonged exposure at levels of 200 – 250 ppm can be fatal. The Worksafe BC regulations define the Short Term Limit ceiling for H2S at 10 ppm.

The highest readings of H2S at the Muskwa Station were 60 ppm which dissipated to near zero after several hours. A trailer court in Fort Nelson showed a high level of 30 ppm. There were no odour calls as a result of the incident. It was felt that the line heaters used up a good portion of this gas. This was a one time event due to the accidental release of higher levels of H2S from Spectra.

13.8 If the delivery of off-spec gas with hazardous H2S content results from upsets or other problems on the Spectra system, please explain why Spectra does not install the H2S monitoring and gas shut-off systems, or pay for Terasen Gas to install them?

Response:

Please see the Response to BCUC IR 1.13.1.

13.9 Please explain what has changed with respect to the Spectra and Terasen Gas systems and the pressures in them, that now requires the upgrading of overpressure protection. If nothing has changed, why is the upgrade justified?

Response:

A prior review of the technical specifications of the Fort Nelson Transmission system resulted in the discovery that one portion of this system has a lower maximum operating pressure than the Spectra system to which the Fort Nelson system is connected. Upgrading only the lower pressure section of pipeline has been considered but a single installation at the beginning of the system was preferable to address additional concerns including a valve at the beginning of the Fort Nelson system that requires replacing to ensure reliability along with adjoining piping alterations. This avoids a second pipeline alteration at the other location.

14.0 Reference: Rate Class 1 – Residential

Exhibit B-1, Section 9, p. 32

14.1 Please explain how the $11.91 in Figure 9 on p. 33 compares to the "Tariff @ 2008 Rates" in column 2 of lines 1-4 in Table 9a.

Response:

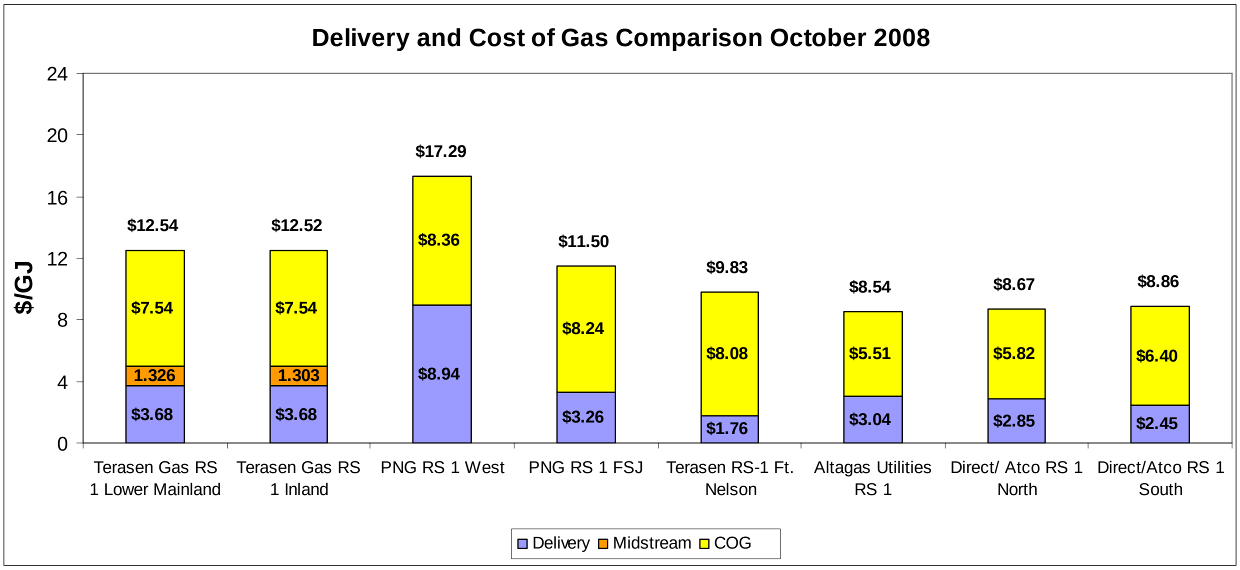
The "Tariff @ 2008 Rates" in column 2 of lines 1-4 in Table 9a of the application dated September 4, 2008 reflects the Gas Cost Recovery Charge of $8.462 per GJ effective April 1, 2008. Figure 9 on page 33 of the application shows the sales rate that reflects the gas cost recovery charge of $10.151 per GJ effective July 1, 2008.

Please find attached below the revised Table 9a and Figure 9, which reflect approved gas cost recovery charge of $8.078 per GJ, effective October 1, 2008 as per the Amended Application dated October 30, 2008.

Table 9a (Amended Oct 30, 2008) – Proposed Tariff Rate change and Rate Class Revenue Recovery

Line No.	Particulars	Tariff @ 2008 Rates	Less: Delivery Rate Rebate (in $/GJ)	Less: RSAM Recovery Charge (in $/GJ)	Less: Average Cost of Gas	Delivery Margin	Margin Rate Increase	Add: Average Cost of Gas	Add: Revised RSAM Recovery Charge	Tariff @ Revised Rates Jan 1/09
1	**Residential**									
2	1st Blk ≤ 2 GJ $ / Month	$ 21.62	$ 0.10	$ (0.23)	$ (16.16)	$ 5.33	$ 2.43	$ 16.16	$ 0.47	$ 24.40
3	2nd Blk Next 28 GJ $ / GJ	$ 9.633	$ 0.050	$ (0.116)	$ (8.078)	$ 1.489	$ 0.518	$ 8.078	$ 0.236	$ 10.321
4	3rd Blk Excess of 30 GJ $ / GJ	$ 9.590	$ 0.050	$ (0.116)	$ (8.078)	$ 1.446	$ 0.502	$ 8.078	$ 0.236	$ 10.262
5										
6	**General Service - Small Commercial**									
7	1st Blk ≤ 2 GJ $ / Month	$ 32.53	$ 0.13	$ (0.23)	$ (16.16)	$ 16.27	$ 6.59	$ 16.16	$ 0.47	$ 39.49
8	2nd Blk Next 298 GJ $ / GJ	$ 9.792	$ 0.066	$ (0.116)	$ (8.078)	$ 1.664	$ 0.575	$ 8.078	$ 0.236	$ 10.553
9	3rd Blk Excess of 300 GJ $ / GJ	$ 9.740	$ 0.066	$ (0.116)	$ (8.078)	$ 1.612	$ 0.556	$ 8.078	$ 0.236	$ 10.482
10										
11	**General Service - Large Commercial**									
12	1st Blk ≤ 2 GJ $ / Month	$ 32.53	$ 0.13	$ (0.23)	$ (16.16)	$ 16.27	$ 6.59	$ 16.16	$ 0.47	$ 39.49
13	2nd Blk Next 298 GJ $ / GJ	$ 9.792	$ 0.066	$ (0.116)	$ (8.078)	$ 1.664	$ 0.575	$ 8.078	$ 0.236	$ 10.553
14	3rd Blk Excess of 300 GJ $ / GJ	$ 9.740	$ 0.066	$ (0.116)	$ (8.078)	$ 1.612	$ 0.556	$ 8.078	$ 0.236	$ 10.482
15										
16	**Transportation Service**									
17	1st Blk ≤ 20 GJ $ / GJ	$ 1.407	$ -	$ -	$ (0.096)	$ 1.311	$ 0.924	$ 0.096		$ 2.331
18	2nd Blk Next 260 GJ $ / GJ	$ 1.304	$ -	$ -	$ (0.096)	$ 1.208	$ 0.852	$ 0.096		$ 2.156
19	3rd Blk Excess of 280 GJ $ / GJ	$ 1.063	$ -	$ -	$ (0.096)	$ 0.967	$ 0.682	$ 0.096		$ 1.745
20	Minimum Delivery Charge per Month	$ 1,076.00				$ 1,076.00	$ 387.00			$ 1,463.00
21										
22	Administration Charge	$ 202.00	$ -	$ -		$ 202.00	$ -			$ 202.00
23	RSAM Recovery Charge	$ 0.116	$ 0.050	$ (0.116)	$ -	$ 0.050		$ -	$ 0.236	$ 0.286

Figure 9 (Amended Oct 30, 2008) – Delivery and Cost of gas comparison at existing rates as of October 1, 2008*



To relate $9.83 in revised Figure 9 (shown above) to the "Tariff @ 2008 Rates" in column 2 of lines 1-4 in the revised Table 9a (shown above), please refer to table below:

TG Fort Nelson Rate Schedule 1B Forecast Usage (in GJ)			140
Fixed Monthly Charge (inclusive of 2 GJ) total per year	$21.62* x 12	=	$259
Fixed Monthly Charge per GJ	$259 / 140	=	$1.85
Total Annual GJ	140 - 24 (inc. in Fixed Monthly)	=	116
		=	
Next 28 GJ in any month @ $9.633* / GJ	$9.633 x 116	=	$1,120
per GJ calculation	$1120 / 140	=	$7.99
Excess of 30 GJ in any month @ $9.590* / GJ	Not Applicable		
Total Rate per GJ (inclusive of Gas Cost Recovery Charge)			**$9.83**
** Refer to column 2, lines 2-4, of revised Table 9a as per the Amended Application*			

14.2 Please confirm if the "Tariff @ 2008 Rates" in column 2 of lines 1-4 in Table 9a are the July 1, 2008 rates or an average of the 2008 rates in effect prior to this Application.

Response:

No, "Tariff @ 2008 rates" in column 2 of lines 1-4 in Table 9a of the Application dated September 4, 2008 reflects approved rates as at April 1, 2008.

The revised Table 9a, as included in the Amended Application dated October 30, 2008 is based on approved rates effective October 1, 2008.

15.0 Reference: Unaccounted for Gas ("UAF")

Exhibit B-1, Section 9, p. 32

15.1 Please explain the how the $0.101 per GJ in column 8, line 19 of Table 9a on p. 32 is calculated, and compare this percentage line loss to the prior years and the five year average.

Response:

$0.101 per GJ in column 8, line 19 of Table 9a on page 32 of the application is calculated from total annual UAF gas cost pertaining to customers served by Rate Schedule 25 ("Transport Customers") and dividing that by total annual demand forecast for transport customers. This is also shown in column 6, line 41 of Schedule 4.2 on page 41 of the application.

Table below shows and compares the actual recorded UAF percentage and UAF percentage incorporated in annual rates from year 2005 to 2009 as per BCUC approved methodology.

TERASEN GAS INC - FORT NELSON SERVICE AREA
UNACCOUNTED FOR GAS ("UAF") PERCENTAGES
FOR THE YEARS 1999 TO 2008

Line No.	Particulars	Recorded 1999	Recorded 2000	Recorded 2001	Recorded 2002	Recorded 2003	Recorded 2004	Recorded 2005	Recorded 2006	Recorded 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Recorded annual UAF percentage	1.76%	3.66%	-1.06%	-3.63%	0.67%	1.48%	1.77%	1.60%	0.55%
2										
3						2005	2006	2007	2008	2009
4						Rates	Rates	Rates	Rates	Rates
5	UAF percentage incorporated in annual rates [(A)]									
6	5-yr average of 1999 to 2003 recorded results					0.3%				
7	5-yr average of 2000 to 2004 recorded results						0.2%			
8	5-yr average of 2001 to 2005 recorded results							-0.2%		
9	5-yr average of 2002 to 2006 recorded results								0.4%	
10	5-yr average of 2003 to 2007 recorded results									1.2%

Notes:

(A) Based on approved methodology, the forecast UAF for rate setting is calculated as the five-year rolling average of the recorded annual UAF percentages.

16.0 Reference: Rate Class 2.3 – Natural Gas Vehicle Fuel Service

Exhibit B-1, Section 9, p. 33

16.1 Please explain why this is the only rate class without a RSAM recovery charge.

Response:

Currently, there are no customers in Rate Schedule 2.3 ("Natural Gas Vehicle Fuel Service") and therefore, there would be no RSAM recovery.

17.0 Reference: Operating & Maintenance

Exhibit B-1, Schedule 7, p. 44

Total labour costs have increased 3.74% from the 2008 Projected to the 2009 Forecast.

17.1 Please confirm the labour inflation increase percentages in the union contracts.

Response:

The COPE and IBEW union labour contracts contain a rate increase of 3% for 2009. It is this increase that explains the majority of the projected increase of 3.74% from the 2008 Projected to the 2009 Forecast. The remaining projected labour increase of 0.74% is the result of a minor increase expected to catch-up on operating and maintenance activities.

17.2 Please explain why Vehicle Costs are expected to increase from $52,000 to $59,000 in 2009.

Response:

The projected vehicle costs for 2009 assume higher gasoline costs resulting from higher oil prices and the introduction of the carbon tax implemented July 1st 2008; together with a higher proportion of field staff time and resources allocated to O&M related work versus capital work.

17.3 On page 45, General and School taxes are forecast to increase from $88,000 to $104,000 in 2009, and 1 percent in Lieu taxes are forecast to increase from $37,000 to $54,000. Further to the discussion on pages 23 and 24, please provide a schedule for 2007, 2008 and 2009 showing for each category of taxes the tax base and the amount of tax payable, and explain the significant forecast increase from 2008 to 2009.

Response:

1% in Lieu Tax

Year		**1% in Lieu Tax ($)**	**Comments**
2007	$	36,009	Actual Reported (2005 Revenues within Town of Fort Nelson Only)
2008		42,040	Actual Reported (2006 Revenues within Town of Fort Nelson Only)
2009		53,883	Based on % Increase in total actual revenues from 2006 to 2007

General & Other Property Taxes

	Property Assessments ($)		Taxes ($)			
	General Assessment	School Assessment	General	School	Other	Total
2007	$ 2,395,400	$ 3,221,400	$28,823	$39,840	$25,451	$94,114
2008	2,562,200	3,449,700	30,486	41,387	26,793	98,666
2009	2,720,300	3,697,500	32,454	42,771	27,944	103,169

Total Property Taxes

	1% in Lieu Tax	General & Other	OGC Fee	Total
2007	36,009	$94,114	$1,129	$131,252
2008	42,040	98,666	1,129	141,835
2009	53,883	103,169	1,129	158,181

Explanation of Variance Increase

1. 1% in Lieu Tax - actual revenues increased between 2005 (2007 Property Taxes) and 2006 (2008 Property Taxes), tax is increased for 2009 by total % change in revenues from gas consumed from 2006 (2008 Property Taxes) to 2007 (2009 Property Taxes).
2. General & Other Property Taxes - increases to pipeline property assessments are expected because of annual additions to distribution mains and services. Estimates are based on approximately 50% of the average reported additions since 2000.
3. Oil & Gas (OGC) Commission Fee is based on reported pipeline lengths at a rate of $25 per Kilometer
4. For 2009 other assumptions include:

	Increase / (Decrease)
Right of Way Land values:	5.0%
Fee Simple Land	8.0%
Office	5.0%
Pipeline / Improvements	4.0%
General Tax Rates	(0.5%)
School Tax Rates	(3.4%)
Other Tax Rates	(2.0%)

18.0 Reference: Property Taxes

Exhibit B-1, Schedule 8, p. 45

The Property Tax deferral account collect all variances from the 2004 Decision Test Year amount (2004-2007).

18.1 Please provide the detail of the Property Tax deferral account since 2004 and how the 2009 Forecast amount in Schedule 8 on p. 45 is derived.

Response:

Subsequent to September 4, 2008 filing, TG Fort Nelson received property tax bill from Fort Nelson Indian Band which was $5000 more than estimated. This has resulted in an increase in the gross additions for 2008 from $17,000 to $22,000 (refer to lines 8 and 9 in the table below). Also, the Opening 2007 balance was corrected to $11,000 (refer to line 4 in the table below) from $14,000. As a result of these changes, the amortization expense for 2009 forecast has increased from $12,000 to $15,000 as shown in lines 11 and 12 of table below. The details regarding the property tax deferral account is on Revised Schedules 17.1 and 17.2 (as shown on lines 3, 18, 35 and 52) of the Amended Application dated October 30, 2008.

Table: Details on Property tax deferral account from 2004 through 2009

Line No.	Particulars	Opening Balance	Gross Additions	Less Taxes	Net Additions	Amortization Expense	Closing Balance
1	2004 Actual	$ -	$ -	$ -	$ -	$ -	$ -
2	2005 Actual	-	(5)	2	(3)	-	(3)
3	2006 Actual	(3)	21	(7)	14	-	11
4	2007 Actual	11	28	(9)	19	-	30
5							
6	2008 Decision	29	-	-	-	(29)	-
7							
8	2008 Projected	30	17	(5)	12	(30)	12
9	2008 Projected Amended Application	30	22	(7)	15	(30)	15
10							
11	2009 Forecast	12	-	-	-	(12)	-
12	2009 Forecast Amended Application	$ 15	$ -	$ -	$ -	$ (15)	$ -

Details for the property tax expense for 2009 are provided in the Response to BCUC IR 1.17.3.

18.2 Please explain when/how the Property Tax deferral account is cleared.

Response:

The amortization of the property tax deferral account has been done as part of revenue requirement applications. TGI Fort Nelson had a revenue requirement application for a forecast test year 2004, 2008 and the current application for 2009. For 2008 the Commission approved the amortization of the projected opening balance of $29 thousand as part of the company's annual cost of service. For 2009 the Company is proposing to amortize the 2008 projected closing balance. The Property Tax Deferral account as set out in the Amended Application has a revised closing balance of $15 thousand dollars.

19.0 Reference: Fixed Assets

Exhibit B-1, Schedule 14.3 Gas Plant in Service, p. 54

The loss in 2008 of one Rate 25 transmission customer could potentially strand or impair the value of the related assets.

19.1 Please explain if the loss of transmission volume is reflected in the retirement of any assets previously used to service that customer.

<u>Response:</u>

The loss in volume to the two transportation service customers, served under Rate Schedule 25, do not require any retirement of assets at this time as gas service is still required for space heating at their facilities. The revised volume and revenues from these two customers, as discussed in the Response to BCUC IR 1.8.2, is included in the Amended Application (see Revised Schedule 4.2, Lines 30 and 41).

20.0 Reference: Long Term Debt

Exhibit B-1, Schedule 19.4, p. 73

20.1 Please explain why the long term debt attributed to Fort Nelson is not at the average embedded cost of the total long term debt.

Response:

The long term debt attributed to Fort Nelson is a notional amount that is an allocation of approximately 0.2% of total long term debt experienced in TGI. This allocation approximates the ratio of Fort Nelson’s rate base over the total rate base of TGI and Fort Nelson combined. Based on figures ($000’s) from the 2007 Annual Report this calculation is $5,048/ ($5,048 + $2,426,180) = 0.002.

The long term debt schedule as filed on September 4, 2008 contained an error in the average embedded cost of the long term debt. TGI has since filed its Advance Materials for the 2008 Annual Review and as such a revised long term debt schedule for Fort Nelson has been prepared and included in the Amended Application materials. The revised Fort Nelson long term debt is $3.035 million with $0.211 million of interest costs at an average embedded rate of 6.692%.

Any difference in forecast interest cost and actual interest cost is added to the deferred interest deferral account.

Attachment 9.1

Attachment 9.1

Revenue, Cost of Service & Revenue to Cost Ratios - Forecast 2009 Rates, Sept. 4, 2008 Filing

Line No.	Particulars	Total	Rate 1	Rate 2.1	Rate 2.2	Rate 25
1						
2	With Pro-forma Cost of Gas added to Rate 25					
3	Revenue					
4	Sales	$ 5,880.6	$ 2,857.3	$ 2,105.7	$ 917.6	
5	T-Service	2,076.3				2,076.3
6	Total Revenue	7,956.9	2,857.3	2,105.7	917.6	2,076.3
7	Class % of Revenue		36%	26%	12%	26%
8	Cost of Gas					
9	Sales	(4,687.3)	(2,289.1)	(1,650.4)	(747.8)	-
10	T-Service	(1,810.0)				(1,810.0)
11	Total Cost of Gas	(6,497.3)	(2,289.1)	(1,650.4)	(747.8)	(1,810.0)
12						
13	Margin					
14	Sales	1,193.3	568.2	455.3	169.8	-
15	T-Service	266.3	-	-	-	266.3
16	Total Margin	1,459.6	568.2	455.3	169.8	266.3
17						
20	Allocated Cost of Service	7,956.9	3,085.0	2,050.9	860.6	1,960.4
21						
23	Revenue to Cost Ratio	100.00%	92.62%	102.67%	106.62%	105.91%

Attachment 10.1a

Attachment 10.1a
Based on Sept 4, 2008 Filing

Fort Nelson RSAM Activity from 2004-2008

	RSAM Activity			Rate Rider Recoveries					
	Activity	Tax	Net of Tax	Rider Recovery	Tax	Net of Tax	Gross Balance	Tax	Net of Tax Balance
2004		34.5%							
Rate 1	$ (6,432)	$ 2,219	$ (4,213)		$ -	$ -	$ (6,432)	$ 2,219	$ (4,213)
Rate 2.1	$ 56,120	$ (19,361)	$ 36,758		$ -	$ -	$ 56,120	$ (19,361)	$ 36,758
Rate 2.2	$ (14,987)	$ 5,171	$ (9,817)		$ -	$ -	$ (14,987)	$ 5,171	$ (9,817)
Rate 25	$ 22,110	$ (7,628)	$ 14,482		$ -	$ -	$ 22,110	$ (7,628)	$ 14,482
Total 2004	$ 56,811	$ (19,600)	$ 37,211	$ -	$ -	$ -	$ 56,811	$ (19,600)	$ 37,211
2005		33.75%							
Open balance Tax Adj							$ (643)	$ 643	$ -
Rate 1	$ 58,910	$ (19,882)	$ 39,028		$ -	$ -	$ 58,910	$ (19,882)	$ 39,028
Rate 2.1	$ 26,674	$ (9,003)	$ 17,672		$ -	$ -	$ 26,674	$ (9,003)	$ 17,672
Rate 2.2	$ (3,163)	$ 1,068	$ (2,096)		$ -	$ -	$ (3,163)	$ 1,068	$ (2,096)
Rate 25	$ 28,266	$ (9,540)	$ 18,726		$ -	$ -	$ 28,266	$ (9,540)	$ 18,726
Total 2005	$ 110,687	$ (37,357)	$ 73,330	$ -	$ -	$ -	$ 166,855	$ (56,314)	$ 110,541
2006		33.0%							
Open balance Tax Adj							$ (1,868)	$ 1,868	$ -
Rate 1	$ 32,762	$ (10,811)	$ 21,950	$ (10,084)	$ 3,328	$ (6,756)	$ 22,678	$ (7,484)	$ 15,194
Rate 2.1	$ 35,937	$ (11,859)	$ 24,077	$ (5,436)	$ 1,794	$ (3,642)	$ 30,500	$ (10,065)	$ 20,435
Rate 2.2	$ 12,462	$ (4,112)	$ 8,349	$ (3,847)	$ 1,269	$ (2,577)	$ 8,615	$ (2,843)	$ 5,772
Rate 25	$ 29,844	$ (9,849)	$ 19,996	$ (13,478)	$ 4,448	$ (9,030)	$ 16,366	$ (5,401)	$ 10,966
Total 2006	$ 111,004	$ (36,631)	$ 74,373	$ (32,845)	$ 10,839	$ (22,006)	$ 243,146	$ (80,238)	$ 162,908
2007		33.0%							
Open balance Tax Adj									$ -
Rate 1	$ 27,704	$ (9,142)	$ 18,561	$ (20,073)	$ 6,624	$ (13,449)	$ 7,631	$ (2,518)	$ 5,113
Rate 2.1	$ 25,646	$ (8,463)	$ 17,183	$ (14,116)	$ 4,658	$ (9,458)	$ 11,530	$ (3,805)	$ 7,725
Rate 2.2	$ 20,555	$ (6,783)	$ 13,772	$ (6,745)	$ 2,226	$ (4,519)	$ 13,810	$ (4,557)	$ 9,253
Rate 25	$ 75,055	$ (24,768)	$ 50,287	$ (19,282)	$ 6,363	$ (12,919)	$ 55,773	$ (18,405)	$ 37,368
Total 2007	$ 148,960	$ (49,157)	$ 99,803	$ (60,216)	$ 19,871	$ (40,345)	$ 331,890	$ (109,524)	$ 222,366
2008 Act-Apr Fore-May-Dec		31.0%							
Open balance Tax Adj							$ (9,620)	$ 9,620	$ -
Rate 1	$ 12,382	$ (3,838)	$ 8,543	$ (32,273)	$ 10,005	$ (22,269)	$ (19,892)	$ 6,166	$ (13,725)
Rate 2.1	$ 32,601	$ (10,106)	$ 22,495	$ (21,886)	$ 6,785	$ (15,101)	$ 10,716	$ (3,322)	$ 7,394
Rate 2.2	$ 48,613	$ (15,070)	$ 33,543	$ (7,617)	$ 2,361	$ (5,256)	$ 40,996	$ (12,709)	$ 28,287
Rate 25	$ (4,113)	$ 1,275	$ (2,838)	$ (25,170)	$ 7,803	$ (17,367)	$ (29,283)	$ 9,078	$ (20,205)
Total 2008	**$ 89,483**	**$ (27,740)**	**$ 61,743**	**$ (86,946)**	**$ 26,953**	**$ (59,993)**	**$ 324,807**	**$ (100,690)**	**$ 224,117**
Summary by Rate Class 2004-2008									
Open balance Tax Adj							$ (12,131)	$ 12,131	$ -
Rate 1	$ 125,326	$ (41,455)	$ 83,871	$ (62,430)	$ 19,956	$ (42,474)	$ 62,896	$ (21,499)	$ 41,397
Rate 2.1	$ 176,978	$ (58,793)	$ 118,185	$ (41,438)	$ 13,237	$ (28,201)	$ 135,540	$ (45,556)	$ 89,985
Rate 2.2	$ 63,479	$ (19,727)	$ 43,752	$ (18,210)	$ 5,857	$ (12,353)	$ 45,270	$ (13,871)	$ 31,399
Rate 25	$ 151,162	$ (50,509)	$ 100,652	$ (57,930)	$ 18,613	$ (39,316)	$ 93,232	$ (31,896)	$ 61,336
Total 2008	**$ 516,945**	**$ (170,484)**	**$ 346,460**	**$ (180,007)**	**$ 57,663**	**$ (122,344)**	**$ 324,807**	**$ (100,690)**	**$ 224,117**

Attachment 10.1a
Based on Sept 4, 2008 Filing

Fort Nelson RSAM Activity from 2004-2008

		RSAM Activity			Rate Rider Recoveries					
		Activity	Tax	Net of Tax	Rider Recovery	Tax	Net of Tax	Gross Balance	Tax	Net of Tax Balance
	Volume	Activity	Tax	Net of Tax	Rider Drawdown	Tax	Net of Tax	Gross Balance	Tax	Net of Tax Balance
Projection to 2011										
2009			30.0%							
Open balance Tax Adj								$ (4,640)	$ 4,640	$ -
Rate 1	270.5		$ -	$ -	$ (38,525)	$ 11,558	$ (26,968)	$ (38,525)	$ 11,558	$ (26,968)
Rate 2.1	195.0		$ -	$ -	$ (27,772)	$ 8,332	$ (19,441)	$ (27,772)	$ 8,332	$ (19,441)
Rate 2.2	88.4		$ -	$ -	$ (12,590)	$ 3,777	$ (8,813)	$ (12,590)	$ 3,777	$ (8,813)
Rate 25	213.9		$ -	$ -	$ (30,464)	$ 9,139	$ (21,325)	$ (30,464)	$ 9,139	$ (21,325)
Total 2009	767.8	$ -	$ -	$ -	$ (109,352)	$ 32,806	$ (76,546)	$ 210,815	$ (63,245)	$ 147,571
RSAM Recovery Charge					$ 0.142					
2010			29.0%							
Open balance Tax Adj								$ (2,969)	$ 2,969	$ -
Rate 1	268.7		$ -	$ -	$ (25,240)	$ 7,320	$ (17,921)	$ (25,240)	$ 7,320	$ (17,921)
Rate 2.1	194.6		$ -	$ -	$ (18,280)	$ 5,301	$ (12,979)	$ (18,280)	$ 5,301	$ (12,979)
Rate 2.2	87.5		$ -	$ -	$ (8,219)	$ 2,384	$ (5,836)	$ (8,219)	$ 2,384	$ (5,836)
Rate 25	213.9		$ -	$ -	$ (20,093)	$ 5,827	$ (14,266)	$ (20,093)	$ 5,827	$ (14,266)
Total 2010	764.7	$ -	$ -	$ -	$ (71,832)	$ 20,831	$ (51,001)	$ 136,014	$ (39,444)	$ 96,570
RSAM Recovery Charge					$ 0.094					
2011			27.5%							
Open balance Tax Adj								$ (2,814)	$ 2,814	$ -
Rate 1	267.7		$ -	$ -	$ (16,431)	$ 4,519	$ (11,913)	$ (16,431)	$ 4,519	$ (11,913)
Rate 2.1	195.0		$ -	$ -	$ (11,969)	$ 3,291	$ (8,677)	$ (11,969)	$ 3,291	$ (8,677)
Rate 2.2	86.6		$ -	$ -	$ (5,315)	$ 1,462	$ (3,854)	$ (5,315)	$ 1,462	$ (3,854)
Rate 25	213.9		$ -	$ -	$ (13,129)	$ 3,610	$ (9,519)	$ (13,129)	$ 3,610	$ (9,519)
Total 2011	**763.2**	**$ -**	**$ -**	**$ -**	**$ (46,845)**	**$ 12,882**	**$ (33,962)**	**$ 86,355**	**$ (23,748)**	**$ 62,608**
RSAM Recovery Charge					$ 0.061					
RSAM Deferred Interest										
2004		$ (229)	$ 79	$ (150)				$ (229)	$ 79	$ (150)
2005		$ 1,890	$ (638)	$ 1,252				$ 1,661	$ (559)	$ 1,102
2006		$ 2,551	$ (842)	$ 1,709				$ 4,212	$ (1,401)	$ 2,811
2007		$ 4,740	$ (1,564)	$ 3,176				$ 8,952	$ (2,965)	$ 5,987
Projected 2008		$ (673)	$ 208	$ (465)				$ 8,279	$ (2,757)	$ 5,522
Forecast 2009		$ (130)	$ 39	$ (91)				$ 8,149	$ (2,718)	$ 5,431
Forecast 2010		$ (161)	$ 47	$ (114)				$ 7,988	$ (2,671)	$ 5,317
Forecast 2011		$ (175)	$ 48	$ (127)				$ 7,813	$ (2,623)	$ 5,190

Attachment 10.1b

Attachment 10.1b

Based on Oct 30, 2008 Revised Application

Fort Nelson RSAM Activity from 2004-2008

	Volume	RSAM Activity			Rate Rider Recoveries					
		Activity	Tax	Net of Tax	Rider Recovery	Tax	Net of Tax	Gross Balance	Tax	Net of Tax Balance
2007 Actual Balance		$ 148,960	$ (49,157)	$ 99,803	$ (60,216)	$ 19,871	$ (40,345)	$ 331,890	$ (109,524)	$ 222,366
2008 Act-Apr Fore-May-Dec Revised			31.0%							
Open balance Tax Adj								$ (9,620)	$ 9,620	$ -
Rate 1		$ 12,382	$ (3,838)	$ 8,543	$ (32,273)	$ 10,005	$ (22,269)	$ (19,892)	$ 6,166	$ (13,725)
Rate 2.1		$ 32,601	$ (10,106)	$ 22,495	$ (21,886)	$ 6,785	$ (15,101)	$ 10,716	$ (3,322)	$ 7,394
Rate 2.2		$ 48,613	$ (15,070)	$ 33,543	$ (7,617)	$ 2,361	$ (5,256)	$ 40,996	$ (12,709)	$ 28,287
Rate 25		$ 66,945	$ (20,753)	$ 46,192	$ (21,275)	$ 6,595	$ (14,680)	$ 45,670	$ (14,158)	$ 31,512
Total 2008		$ 160,541	$ (49,768)	$ 110,773	$ (83,051)	$ 25,746	$ (57,305)	$ 399,760	$ (123,926)	$ 275,834
Summary by Rate Class 2004-2008 Revised										
Open balance Tax Adj								$ (12,131)	$ 12,131	$ -
Rate 1		$ 125,326	$ (41,455)	$ 83,871	$ (62,430)	$ 19,956	$ (42,474)	$ 62,896	$ (21,499)	$ 41,397
Rate 2.1		$ 176,978	$ (58,793)	$ 118,185	$ (41,438)	$ 13,237	$ (28,201)	$ 135,540	$ (45,556)	$ 89,985
Rate 2.2		$ 63,479	$ (19,727)	$ 43,752	$ (18,210)	$ 5,857	$ (12,353)	$ 45,270	$ (13,871)	$ 31,399
Rate 25		$ 222,220	$ (72,537)	$ 149,683	$ (54,035)	$ 17,406	$ (36,629)	$ 168,185	$ (55,131)	$ 113,054
Total 2008		$ 588,003	$ (192,513)	$ 395,491	$ (176,112)	$ 56,456	$ (119,656)	$ 399,760	$ (123,926)	$ 275,834
	Volume									
Projection to 2011										
2009			30.0%							
Open balance Tax Adj								$ (5,711)	$ 5,711	$ -
Rate 1	270.5				$ (63,864)	$ 19,159	$ (44,705.1)	$ (63,864)	$ 19,159	$ (44,705)
Rate 2.1	195.0				$ (46,039)	$ 13,812	$ (32,227.3)	$ (46,039)	$ 13,812	$ (32,227)
Rate 2.2	88.4				$ (20,871)	$ 6,261	$ (14,609.7)	$ (20,871)	$ 6,261	$ (14,610)
Rate 25	13.8				$ (3,258)	$ 977	$ (2,280.7)	$ (3,258)	$ 977	$ (2,281)
Total 2009	567.7				$ (134,033)	$ 40,209.8	$ (93,822.8)	$ 260,017	$ (78,005)	$ 182,012
RSAM Recovery Charge					$ 0.236					

Attachment 10.1b

Based on Oct 30, 2008 Revised Application

Fort Nelson RSAM Activity from 2004-2008

		RSAM Activity			Rate Rider Recoveries					
		Activity	Tax	Net of Tax	Rider Recovery	Tax	Net of Tax	Gross Balance	Tax	Net of Tax Balance
2010			29.0%							
Open balance Tax Adj								$ (3,662)	$ 3,662	$ -
Rate 1	268.7				$ (41,900)	$ 12,151	$ (29,749)	$ (41,900)	$ 12,151	$ (29,749)
Rate 2.1	194.6				$ (30,345)	$ 8,800	$ (21,545)	$ (30,345)	$ 8,800	$ (21,545)
Rate 2.2	87.5				$ (13,644)	$ 3,957	$ (9,688)	$ (13,644)	$ 3,957	$ (9,688)
Rate 25	13.8				$ (2,152)	$ 624	$ (1,528)	$ (2,152)	$ 624	$ (1,528)
Total 2010	564.6				$ (88,042)	$ 25,532	$ (62,510)	$ 168,312	$ (48,811)	$ 119,502
RSAM Recovery Charge					$ 0.156					
2011			27.5%							
Open balance Tax Adj								$ (3,482)	$ 3,482	$ -
Rate 1	267.7				$ (27,294)	$ 7,506	$ (19,788)	$ (27,294)	$ 7,506	$ (19,788)
Rate 2.1	195.0				$ (19,882)	$ 5,468	$ (14,414)	$ (19,882)	$ 5,468	$ (14,414)
Rate 2.2	86.6				$ (8,830)	$ 2,428	$ (6,402)	$ (8,830)	$ 2,428	$ (6,402)
Rate 25	13.8				$ (1,407)	$ 387	$ (1,020)	$ (1,407)	$ 387	$ (1,020)
Total 2011	**563.1**				$ (57,413)	$ 15,789	$ (41,625)	$ 107,417	$ (29,540)	$ 77,877
RSAM Recovery Charge					$ 0.102					
RSAM Deferred Interest										
2004		$ (229)	$ 79	$ (150)				$ (229)	$ 79	$ (150)
2005		$ 1,890	$ (638)	$ 1,252				$ 1,661	$ (559)	$ 1,102
2006		$ 2,551	$ (842)	$ 1,709				$ 4,212	$ (1,401)	$ 2,811
2007		$ 4,740	$ (1,564)	$ 3,176				$ 8,952	$ (2,965)	$ 5,987
Projected 2008		$ (512)	$ 159	$ (353)				$ 8,440	$ (2,806)	$ 5,634
Forecast 2009		$ (166)	$ 50	$ (116)				$ 8,274	$ (2,756)	$ 5,518
Forecast 2010		$ (205)	$ 59	$ (146)				$ 8,069	$ (2,697)	$ 5,372
Forecast 2011		$ (223)	$ 61	$ (162)				$ 7,846	$ (2,636)	$ 5,210

Attachment 10.2

Fort Nelson RSAM Activity from 2004-2008

Excluding Rate 25 Customers from RSAM Recovery from 2009 - 2011

	RSAM Activity			Rate Rider Recoveries					
	Activity	Tax	Net of Tax	Rider Recovery	Tax	Net of Tax	Gross Balance	Tax	Net of Tax Balance
2004		34.5%							
Rate 1	$ (6,432)	$ 2,219	$ (4,213)		$ -	$ -	$ (6,432)	$ 2,219	$ (4,213)
Rate 2.1	$ 56,120	$ (19,361)	$ 36,758		$ -	$ -	$ 56,120	$ (19,361)	$ 36,758
Rate 2.2	$ (14,987)	$ 5,171	$ (9,817)		$ -	$ -	$ (14,987)	$ 5,171	$ (9,817)
Rate 25	$ 22,110	$ (7,628)	$ 14,482		$ -	$ -	$ 22,110	$ (7,628)	$ 14,482
Total 2004	$ 56,811	$ (19,600)	$ 37,211	$ -	$ -	$ -	$ 56,811	$ (19,600)	$ 37,211
2005		33.75%							
Open balance Tax Adj							$ (643)	$ 643	$ -
Rate 1	$ 58,910	$ (19,882)	$ 39,028		$ -	$ -	$ 58,910	$ (19,882)	$ 39,028
Rate 2.1	$ 26,674	$ (9,003)	$ 17,672		$ -	$ -	$ 26,674	$ (9,003)	$ 17,672
Rate 2.2	$ (3,163)	$ 1,068	$ (2,096)		$ -	$ -	$ (3,163)	$ 1,068	$ (2,096)
Rate 25	$ 28,266	$ (9,540)	$ 18,726		$ -	$ -	$ 28,266	$ (9,540)	$ 18,726
Total 2005	$ 110,687	$ (37,357)	$ 73,330	$ -	$ -	$ -	$ 166,855	$ (56,314)	$ 110,541
2006		33.0%							
Open balance Tax Adj							$ (1,868)	$ 1,868	$ -
Rate 1	$ 32,762	$ (10,811)	$ 21,950	$ (10,084)	$ 3,328	$ (6,756)	$ 22,678	$ (7,484)	$ 15,194
Rate 2.1	$ 35,937	$ (11,859)	$ 24,077	$ (5,436)	$ 1,794	$ (3,642)	$ 30,500	$ (10,065)	$ 20,435
Rate 2.2	$ 12,462	$ (4,112)	$ 8,349	$ (3,847)	$ 1,269	$ (2,577)	$ 8,615	$ (2,843)	$ 5,772
Rate 25	$ 29,844	$ (9,849)	$ 19,996	$ (13,478)	$ 4,448	$ (9,030)	$ 16,366	$ (5,401)	$ 10,966
Total 2006	$ 111,004	$ (36,631)	$ 74,373	$ (32,845)	$ 10,839	$ (22,006)	$ 243,146	$ (80,238)	$ 162,908
2007		33.0%							
Open balance Tax Adj									$ -
Rate 1	$ 27,704	$ (9,142)	$ 18,561	$ (20,073)	$ 6,624	$ (13,449)	$ 7,631	$ (2,518)	$ 5,113
Rate 2.1	$ 25,646	$ (8,463)	$ 17,183	$ (14,116)	$ 4,658	$ (9,458)	$ 11,530	$ (3,805)	$ 7,725
Rate 2.2	$ 20,555	$ (6,783)	$ 13,772	$ (6,745)	$ 2,226	$ (4,519)	$ 13,810	$ (4,557)	$ 9,253
Rate 25	$ 75,055	$ (24,768)	$ 50,287	$ (19,282)	$ 6,363	$ (12,919)	$ 55,773	$ (18,405)	$ 37,368
Total 2007	$ 148,960	$ (49,157)	$ 99,803	$ (60,216)	$ 19,871	$ (40,345)	$ 331,890	$ (109,524)	$ 222,366
2008 Act-Apr Fore-May-Dec		31.0%							
Open balance Tax Adj							$ (9,620)	$ 9,620	$ -
Rate 1	$ 12,382	$ (3,838)	$ 8,543	$ (32,273)	$ 10,005	$ (22,269)	$ (19,892)	$ 6,166	$ (13,725)
Rate 2.1	$ 32,601	$ (10,106)	$ 22,495	$ (21,886)	$ 6,785	$ (15,101)	$ 10,716	$ (3,322)	$ 7,394
Rate 2.2	$ 48,613	$ (15,070)	$ 33,543	$ (7,617)	$ 2,361	$ (5,256)	$ 40,996	$ (12,709)	$ 28,287
Rate 25	$ 66,945	$ (20,753)	$ 46,192	$ (21,275)	$ 6,595	$ (14,680)	$ 45,670	$ (14,158)	$ 31,512
Total 2008	**$ 160,541**	**$ (49,768)**	**$ 110,773**	**$ (83,051)**	**$ 25,746**	**$ (57,305)**	**$ 399,760**	**$ (123,926)**	**$ 275,834**

Fort Nelson RSAM Activity from 2004-2008

Excluding Rate 25 Customers from RSAM Recovery from 2009 - 2011

	RSAM Activity			Rate Rider Recoveries					
	Activity	Tax	Net of Tax	Rider Recovery	Tax	Net of Tax	Gross Balance	Tax	Net of Tax Balance
Summary by Rate Class 2004-2008									
Open balance Tax Adj							$ (12,131)	$ 12,131	$ -
Rate 1	$ 125,326	$ (41,455)	$ 83,871	$ (62,430)	$ 19,956	$ (42,474)	$ 62,896	$ (21,499)	$ 41,397
Rate 2.1	$ 176,978	$ (58,793)	$ 118,185	$ (41,438)	$ 13,237	$ (28,201)	$ 135,540	$ (45,556)	$ 89,985
Rate 2.2	$ 63,479	$ (19,727)	$ 43,752	$ (18,210)	$ 5,857	$ (12,353)	$ 45,270	$ (13,871)	$ 31,399
Rate 25	$ 222,220	$ (72,537)	$ 149,683	$ (54,035)	$ 17,406	$ (36,629)	$ 168,185	$ (55,131)	$ 113,054
Total 2008	**$ 588,003**	**$(192,513)**	**$ 395,491**	**$(176,112)**	**$ 56,456**	**$(119,656)**	**$ 399,760**	**$ (123,926)**	**$ 275,834**

	Volume	Activity	Tax	Net of Tax	Rider Drawdown	Tax	Net of Tax	Gross Balance	Tax	Net of Tax Balance
Projection to 2011										
2009			30.0%							
Open balance Tax Adj								$ (4,640)	$ 4,640	$ -
Rate 1	270.5		$ -	$ -	$ (65,456)	$ 19,637	$ (45,819)	$ (65,456)	$ 19,637	$ (45,819)
Rate 2.1	195.0		$ -	$ -	$ (47,186)	$ 14,156	$ (33,030)	$ (47,186)	$ 14,156	$ (33,030)
Rate 2.2	88.4		$ -	$ -	$ (21,391)	$ 6,417	$ (14,974)	$ (21,391)	$ 6,417	$ (14,974)
Rate 25	-		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total 2009	553.9	$ -	$ -	$ -	$(134,033)	$ 40,210	$ (93,823)	$ 261,087	$ (79,076)	$ 182,012
RSAM Recovery Charge					$ 0.242					
2010			29.0%							
Open balance Tax Adj								$ (4,733)	$ 4,733	$ -
Rate 1	268.7		$ -	$ -	$ (42,950)	$ 12,456	$ (30,495)	$ (42,950)	$ 12,456	$ (30,495)
Rate 2.1	194.6		$ -	$ -	$ (31,106)	$ 9,021	$ (22,085)	$ (31,106)	$ 9,021	$ (22,085)
Rate 2.2	87.5		$ -	$ -	$ (13,986)	$ 4,056	$ (9,930)	$ (13,986)	$ 4,056	$ (9,930)
Rate 25	-		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total 2010	550.8	$ -	$ -	$ -	$ (88,042)	$ 25,532	$ (62,510)	$ 168,312	$ (48,811)	$ 119,502
RSAM Recovery Charge					$ 0.160					
2011			27.5%							
Open balance Tax Adj								$ (3,482)	$ 3,482	$ -
Rate 1	267.7		$ -	$ -	$ (27,980)	$ 7,695	$ (20,286)	$ (27,980)	$ 7,695	$ (20,286)
Rate 2.1	195.0		$ -	$ -	$ (20,382)	$ 5,605	$ (14,777)	$ (20,382)	$ 5,605	$ (14,777)
Rate 2.2	86.6		$ -	$ -	$ (9,051)	$ 2,489	$ (6,562)	$ (9,051)	$ 2,489	$ (6,562)
Rate 25	-		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total 2011	549.3	$ -	$ -	$ -	$ (57,413)	$ 15,789	$ (41,625)	$ 107,417	$ (29,540)	$ 77,877
RSAM Recovery Charge					$ 0.105					

Attachment 10.2

Fort Nelson RSAM Activity from 2004-2008

Excluding Rate 25 Customers from RSAM Recovery from 2009 - 2011

	RSAM Activity			Rate Rider Recoveries					
	Activity	Tax	Net of Tax	Rider Recovery	Tax	Net of Tax	Gross Balance	Tax	Net of Tax Balance
RSAM Deferred Interest									
2007	$ 4,740	$ (1,564)	$ 3,176				$ 8,952	$ (2,965)	$ 5,987
Projected 2008	$ (512)	$ 159	$ (353)				$ 8,440	$ (2,806)	$ 5,634
Forecast 2009	$ (166)	$ 50	$ (116)				$ 8,274	$ (2,756)	$ 5,518
Forecast 2010	$ (205)	$ 59	$ (146)				$ 8,069	$ (2,697)	$ 5,372
Forecast 2011	$ (223)	$ 61	$ (162)				$ 7,846	$ (2,636)	$ 5,210