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November 17, 2004

British Columbia Utilities Commission
Sixth Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Mr. Robert J. Pellatt, Commission Secretary

Dear Sir:

RE: Terasen Gas Inc. ("Terasen Gas")
2004 Annual Review
Terasen Gas Response to British Columbia Public Interest Advocacy Centre ("BCOAPO") Information Request No. 1

Terasen Gas respectfully submits the attached responses to BCOAPO Information Request No. 1.

Twenty copies will be sent to the Commission office, Thursday November 18th, 2004.

Yours very truly,

TERASEN GAS INC.

Original signed by Tom Loski

For: Scott A. Thomson

Attachment

cc. Registered Intervenors

Question: 1 Reference: A-4 - Gas Sales and Transportation Volumes, pages 3-5 and B-8 Miscellaneous Information, pages 16-17

a) Given the stronger economic outlook for 2005 relative to 2004, and the company's strategic focus to achieve higher growth in 2005, please comment on why the residential customer attachments for 2005 is lower then 2004, even after assuming the 1,500 customers attached in 2003 are removed from the 2004 number.

Response:

The slight reduction in the forecast number of residential attachments in 2005 reflects the shift towards a larger share of forecast multiple-family construction of total starts and the way in which customers are counted.

In 2004 multiple-family starts are projected to comprise 56.8% of total starts; in 2005 this share is expected to increase to 57.4%. Multiple-family construction results in the installation of either one meter for an entire complex, or individual meters for each dwelling unit. Most construction of this type has a single meter installed. Terasen counts customers on the basis of meters installed. If the portion of housing starts shifts more towards multiple-family developments, then the number of meters that can be counted as customers will be reduced.

Finally, single meter multiple-family developments have higher load than individually metered multiple-family-dwelling-units and will be added as a commercial and not as a residential customer.

The customer additions forecast for 2005 reflects this understanding – residential additions are expected to be slightly lower and commercial additions slightly higher than those for 2004.

b) Please provide the detailed numerical calculation underpinning the residential customer attachment projection and forecast for 2004 and 2005, respectively.

Response:

Please see responses to MEM IR 1, question 1.1; and BCUC IR 1 questions 5.1, 5.2, and 5.3.

Question: 2 Reference: A-4 Gas Sales and Transportation Volumes, page 6-7

a) Please provide the objective evidence Terasen relied upon to confirm their belief of a customer lifestyle change, whereby homeowner preference shifts towards apartment-style condominiums and townhouse.

Response:

The belief that homeowner preferences are shifting towards apartment-style condominiums and townhouses is based on the increasing share that multiple-family-developments make of total housing starts. The share of multiple-family-starts is expected to increase from 53.2% of total starts in 2003 to a forecast 57.4% in 2005 according to recent CMHC reporting (BC Housing Now, October 2004). Multiple-family-housing typically includes low and high rise condominiums, and townhouses. The shift towards a greater proportion of multiple-family-construction appears to be in response to demand for more affordable housing as well as lifestyle choice.

b) For each rate class, please specifically identify the impact to annual rate use for following factors: historical use per account, customer migration, forecast use for new customer additions, appliance conversion or replacement effects, and demand side management programs. Does Terasen rely upon a regression analysis to quantify these impacts for the forecast and projected years?

Response:

Please see response to BCUC IR 1, question 6.1.

c) What is the rationale for the expected decline in Rate 3 and Rate 23 for the 2005 Forecast year relative to the 2004 Projected year?

Response:

Please see response to BCUC IR 1, questions 6.2 and 6.3.

Question: 3 Reference: A-4 Gas Sales and Transportation Volumes, page 8

a) Please comment if Terasen takes into consideration the stronger economic outlook in 2005 when establishing the 2005 industrial volume forecast? If not, why not.

Response:

Yes, the economic outlook for 2005 is taken into consideration when compiling the 2005 industrial energy forecast. Although 2005 volumes are not adjusted directly for the stronger economic outlook using an explicit "economic growth factor", the economic outlook is incorporated indirectly in a number of ways.

Customers who responded to the Industrial Customer Volume Survey are assumed to have taken the economic outlook into consideration and how it will impact their business.

For customers who did not respond to this year's survey, the volume forecast was based on the most recent twelve months of data available (this included actual consumption up to August 2004 at the time the forecast was compiled). This methodology was used in order to capture some of the process changes that may have occurred since the beginning of 2003 as a result of changing economic conditions in BC. Once this analysis was completed, the economic outlook for BC was then used as a measure of the overall reasonableness of the analysis-driven forecast.

b) Did Terasen adjust any of the customer survey volumes?

Response:

No, survey volumes were entered into the forecast as they had been recorded by the customer on their returned survey. However, in keeping with the methodology used in previous forecasts, the industrial energy forecast for 2005 also incorporates a strike adjustment for all regions and rate classes, and curtailment adjustments for rates 7, 22 (except Burrard Thermal and Bypass accounts) and 27 in all regions. These adjustments are calculated as separate inputs into the industrial energy forecast.

c) Please provide a comparison in aggregate of the actual volumes used by the survey respondent in the last two years, and the projected volumes provided by these customers for 2005.

Volumes for survey respondents are set out in the following table.

	Annual Survey Volume (TJs)			
	2002a	2003a	2004f	2005f
Rate 5	881.4	938.0	953.0	989.6
Rate 7	26.0	22.6	16.8	17.1
Rate 22	27,174.2	26,081.9	24,924.9	24,481.9
Rate 25	6,810.8	6,971.7	6,968.8	7,358.6
Rate 27	4,336.9	4,126.8	3,963.8	4,133.8
TOTAL	39,229.3	38,140.9	36,827.4	36,981.0

Please note that these volumes may not relate directly to previously filed schedules as they do not include any strike or curtailment adjustments, and are adjusted to reflect rate class switching.

d) *For the customers with no survey responses, please provide the aggregate actual volumes for the last 2 years and the projected volumes for 2004 and 2005 for these customers.*

Response:

Volumes for customers who did not respond to the survey are set out in the following table.

	Annual Non-Survey Volume (TJs)			
	2002a	2003a	2004f	2005f
Rate 5	3,438.6	3,522.7	3,687.8	3,840.9
Rate 7	69.3	63.6	56.7	58.2
Rate 22	13,520.2	12,539.3	13,031.5	12,921.3
Rate 25	7,073.6	6,964.7	6,964.6	7,075.7
Rate 27	2,451.2	2,217.3	1,682.2	1,717.1
TOTAL	26,553.0	25,307.6	25,422.8	25,613.3

Please note that these volumes may not relate directly to previously filed schedules as they do not include any strike or curtailment adjustments, and are adjusted to reflect rate class switching.

Question: 4 Reference: Section A, Tab 4, page 16

Please expand the other operating revenue information to include the last 2 years of actuals (i.e., 2002, and 2003), and the 2004 projection information (i.e., 2004 incorporates the actuals to August 2004).

Response:

Please see the table below,

($000)	2002 Actual	2003 Actual	2004 Projection	2005 Forecast
Late Payment Charge	1,976	3,184	3,079	5,003
Connection Charge/NSF Check	3,821	3,902	4,397	4,192
TGVI Wheeling Charge	3,877	3,874	3,975	4,094
SCP Third Party Revenue	12,729	8,500	8,820	11,897
Others	2,584	1,351	1,429	1,189
Total Other Operating Revenue	24,987	20,811	21,700	26,375

Question: 5 Reference: Section A, Tab 5, page 2

Please provide the detailed calculation underpinning the change amounts (columns 3, 6, and 8) for the Total Gross O&M Expense amounts.

Response:

The change amounts under Column 3 reflect the change from 2003 Decision O&M to the 2004 formula allowed O&M expenses. Based on the forecast of average customer growth of 0.96% and CPI of 1.7% in October 2003, the formula based 2004 Gross O&M is expected to be 3.3 million higher than 2003 Decision amounts. The calculation is as following,

2004 Gross O&M = $182,420 x (1+0.962%) x (1+1.7%-0.85) = $185,740
Change from 2003 = $185,740 - $182,420 = $3,320

The change amounts under Column 6 reflect the change from 2003 Decision O&M to the Adjusted 2004 O&M. When TGI filed its 2003 Annual Review, the average customer growth of 0.96% is forecast based on projected 2003 customer accounts and 2004 forecast. For the purpose of 2005 rates setting, 2004 formula based O&M expenses have been adjusted based on updated 2004 customer growth of 1.15%. Per PBR settlement, there is no true-up for CPI. So based on updated average customer growth of 1.15%, the 2004 Gross O&M amount that will be used as the base to calculate 2005 O&M will be $186,089.

2004 Adjusted Gross O&M = $182,420 x (1+1.152%) x (1+1.7%-0.85%) = $186,089
Change from 2003 = $186,089 - $182,420 = $3,669

The change amounts under column 8 reflect the change from 2004 Adjusted O&M base to the 2005 formula based O&M. Based on the forecast of average customer growth of 1.4% and CPI of 2%, the 2005 Gross O&M is expected to be 4.5 million higher than 2004 Adjusted O&M expenses.

2005 Gross O&M = $186,089 x (1+1.397%) x (1+2%-1%) = $190,575
Change from Adjusted 2004 = $190,575 - $186,089 = $4,486

Question: 6 Reference: A-8 2004 Projections and Appendix A, to Order No. G-51-03, page 9 of 47

"In LMLGUA IR 13, the Company confirmed that if it incurs restructuring costs and efficiencies do not materialize then the restructuring costs are borne by the Company"

Given the reference Settlement statement above, please comment on why customers are sharing in the 2004 earning sharing shortfall that is resulting from insufficient efficiencies being realized to offset the restructuring costs.

Response:

The referenced statement in the settlement refers to the Company's response to LMLGUA IR 13 which concerned the Company's original proposal to deal with restructuring costs which were to capture such costs in a deferral account and apply savings first to recapture the restructuring costs before sharing commenced. The Company was prepared to absorb any net restructuring costs if a balance still existed at the end of the settlement period. That is what the Company proposed. The parties ultimately settled on restructuring costs incurred in 2003 being recovered as a 2004 expense. This is what was reflected in the filing.

Question: 7 Reference: B-1 Five Year Major Capital Plan, Intermediate Pressure Systems, page 2-3

Does Terasen carry out a priority ranking of the projects in the capital plan? If so please identify the priority criteria and how Terasen determines the priority of one project over another. In addition, please list the capital projects based on priority.

Response:

With respect to projects identified in section B-1 Five Year Major Capital Plan 2.0 Areas of Capacity Shortfall, the projects that have been identified are all required to maintain minimum gas system pressures at the tail-ends of the respective gas systems.

The five year gas system peak load projections are updated annually to reflect actual customer load growth and areas of capacity shortfall. The gas system hydraulic models are evaluated using this updated load information. The results of the hydraulic evaluations are analyzed and system improvement projects are prioritized based on the timing and severity of the capacity shortfalls in each pressure system.

Of the four projects identified in B-1 Five Year Major Capital Plan, Intermediate Pressure Systems, page 2-3, Project 2.4.1 Riverside Road, Abbotsford is required as a result of the cumulative load growth in the Abbotsford/Mission area eroding the capacity of the King Intermediate Pressure system.

The remaining three projects identified: 2.4.2 72nd Street to 36th Avenue, Delta; 2.4.3 Goudy Road and 36th Avenue, Delta and 2.4.4 34B Avenue to 57th Street, Delta are driven by forecasted greenhouse load increases in the Delta area. These projects have been identified as the drivers for system reinforcement but will be subject to detailed load forecast verification and economic assessments prior to construction. Please note that the title for one project was filed incorrectly as "34B to 57th Avenue, Delta". This title should be "34B **Avenue** to 57th **Street**, Delta".

All four projects are prioritized based on the latest years that construction completion would be required to ensure that capacity is available to meet minimum tail-end system pressures of the respective gas systems if all loads are verified as currently forecasted.

Question: 8 Reference: B-2 Service Quality Indicators, page 3

a) *How was the Emergency Response Time benchmark determined?*

Response:

The 2004 benchmark for Emergency Response Time was set by taking a simple average of the actual annual results for 2000, 2001 and 2002. 2003 year-end results were not available at the time the 2004 benchmark was set, so they were not included in determining the benchmark.

b) *Please confirm that this benchmark was considered to be reasonable by Terasen at the time the benchmark was established. Does Terasen now view this benchmark to be inappropriate?*

Response:

This benchmark was considered to be reasonable by Terasen Gas at the time the benchmark was established. However, Terasen Gas has previously expressed its concern that the process of using three-year averages to set the benchmark results in a continually tighter benchmark.

Terasen Gas' statement on page 3 regarding the 2004 year-to-date Emergency Response Time was,

"While this exceeds the benchmark, the variance is less than 2% and represents an improvement over 2003."

Question: 9 Reference: B-2 Transmission System Integrity (Transmission System Annual Reportable Incidents), pages 5-6:

Please describe the "Annual Reportable Incidents" as tallied in the table on page 6 for the years 2002, 2003 and 2004 (Jan-Sept), including their nature, severity and cost of repair.

Response:
Please refer to the table below.

Year	Transmission System Annual Reportable Incidents	Incident Nature and Severity	Estimated Cost of Repair
2004 (Jan - Sept)	1	1. Corrosion leak on 3" transmission pipeline near Fort Nelson. Minor severity.	$3,000.
2003	3	1. Uncontrolled release of transmission-pressure gas to atmosphere. Caused by failure of stop-off equipment sealing element due to manufacturing defect. Minor severity. 2. Contractor fatality during installation of 10" transmission piping near Rossland. Major severity. 3. Small (bubble) leak on weld on 3" transmission-pressure piping at regulator station inlet. Minor severity.	$2,500. N/A $1,000
2002	1	1. Small leak on 12" Interior Transmission system mainline. Minor severity.	$5,000.

Question: 10 Reference: B-2 Service Quality Indicators, page 11

a) Please comment on why Terasen Gas is of the view that the increase in customer complaints is due to billing, when the billing calls in 2004 YTD are in fact below the number filed for 2003, by 1.

Response:

Terasen Gas' statement on page 11 was:

> "During 2004, Terasen Gas has reviewed customer complaints to the BCUC and found that, although the number of complaints has increased over 2003 levels, the majority of complaints deal with billing and collection matters where Terasen Gas has appropriately applied approved tariffs in an effort to improve collections and reduce bad debts for the benefit of all customers.

Although the Billing complaints in 2004 YTD are below the 2003 level, the 2004 year-end Billing complaints will be higher than 2003. Similarly, the 2004 year-end Collections complaints will be significantly higher than 2003.

b) Please confirm the complaints in 2004 are increasing due to customers concerns with regards to Terasen's "Service".

Response:

There are a small number of customers with billing and collection issues where Terasen Gas has appropriately applied approved tariffs in an effort to improve collections and reduce bad debts for the benefit of all customers. These affected customers are vocal in their complaints about Terasen Gas' "service".

c) Please explain how Terasen's implementation of approved tariffs were an effort to improve collections and reduce bad debts for the benefit of all customers. What improved collection methods were implemented which clearly were not viewed acceptable to customers?

Response:

The cited reference of Section B-2, page 11 does not deal with the implementation of approved tariffs but rather refers to the appropriate application of approved tariffs. This refers to Sections 6 and 23 of the General Terms and Conditions of the Terasen Gas Inc. tariff which deal with Security for Payment of Bills and Discontinuance of or Refusal of Service. Appropriate application of the provisions of these tariff sections has been utilized in the management of bad debt.

d) Please identify the bad debt benefit that has been realized by all customers.

Response:

Bad debt has been reduced in 2004 from the amount implicit in the O&M formula. This has improved the Earnings Sharing Benefit available to customers by 50% of this difference.

Question: 11 Reference: B-4 Material Efficiency Measures, pages 1-4

a) Please identify the internal cost the Terasen Gas measurement technologies group or other departments incurred in developing this method of testing high-pressure meters?

Response:

As part of the measurement technology group's operations, meter testing due diligence and ongoing meter testing investigation, research and evaluation is regularly undertaken with the objectives of increasing efficiency and ensuring compliance with evolving standards. When the Triple Point project was identified as unique and distinct, all incremental costs involved in proving the concept were allocated to the capital cost of the project. At the point in time when Terasen Gas has determined how it will proceed with marketing arrangements for the service (external or internal) and therefore a pricing structure, it will apply to the Commission for approval of the regulatory construct and copy the parties to the negotiated settlement. A financial analysis will be included with the application.

b) When did design of this process begin?

Response:

Terasen Gas has been in a process to determine better and more efficient methods to test its high pressure meters over a period of 6-7 years. The Triple Point Concept began in early 2003.

c) Is Terasen currently using this Triple Point process for their high-pressure meters?

Response:

No, the meter testing facilities have not been completed and as such Terasen Gas is not in a position to test its own meters using the Triple Point process. Terasen Gas anticipates it will be testing its own meters by the second quarter of 2005.

d) Would the Terasen Gas family of companies be sufficient to generate enough revenues to offset the incremental revenue requirement attributable to the new facility?

Response:

Yes, over the life of the facility internal demand justifies the capital expenditure at current volumes, but third party revenues enhance the project economics.

e) *When is Terasen hoping to submit an application to the commission for review and approval?*

Response:

Please see response to BCUC IR 15.1.

Question: 12 Reference: B-4 Material Efficiency Measures

Preamble: "A feasibility study is now being completed but the timing and projected cost of the conversion and related benefits are not known and have not been included in this report."

a) Please provide a copy of the feasibility study.

Response:

Terasen Gas is in the process of completing the feasibility study and as such is unable to provide a copy of the study at this time.

b) Will an assessment of the cost of the conversion and the related benefits be carried out prior to a making a decision to proceed?

Response:

Yes, TGVI is assessing the cost of conversion and the related benefits. TGVI will file a CPCN Application in Q1 2005 if the financial evaluation concludes that the conversion of TGVI customers from the current Banner CIS to the Energy CIS demonstrates a lower revenue requirement to TGVI customers.

Question: 13 Reference: October 20, 2004 – Shared Services Management Agreement – update

a) Given that the capital investments of $8 million will reside on the TGI books as well as the $2.4 million for the SAP technology platform, please discuss how Terasen will treat these capital costs in the PBR Plan. Are these capital costs to be treated as if it were a CPCN Addition? Please explain.

<u>Response:</u>

The capital investments of $8 million will reside on the books of TGVI not TGI. The allocation of the pre-existing SAP investment of $2.4 million (i.e. 10% of $24 million NBV) continues to reside on TGI's books. There is no impact under the PBR of continuing to carry such assets on the books of TGI as the TGI plant assets are set by formula. Consequently TGI will not be filing a CPCN application as it will not be making any investments relating to the assets in question.

b) Is Terasen seeking approval by the Commission at this Annual Review for a change to the asset transfer?

<u>Response:</u>

Terasen is not actually transferring assets as originally proposed to the Commission. It is simply seeking approval to recover the costs associated with those assets from TGVI in a manner that would render it consistent with the impact had such a transfer taken place. TGI has created efficiency through the more effective utilization of the SAP assets as part of the integration project. The benefit will be shared with customers in the same manner it would have had the asset transfer occurred.

Question: 14 Reference: B-7, Coastal Facilities Project - "Current Developments" pages 2-6:

Please describe the scenario where the debt-to-equity financing of the Project were set so as to evenly balance the financial impact on shareholders and ratepayers, including an analysis similar to that of the other alternatives presented in the table on page 5.

Response:

As noted in the 2005 annual review advance material, Section B Tab 7, Terasen Gas does not believe that the incremental cost associated with the coastal facilities accounting change should be borne by shareholders since BCUC Order Number C-14-98 explicitly stated "the Company shareholders will be protected from the impact of changes to the current accounting and tax rules" and "if it is not feasible to renew the lease arrangement, the outstanding costs of the Project may be financed as a traditional rate base item." Accordingly, any scenario that negatively impacts the shareholders will not conform to the direction of the BCUC Order cited above.

Question: 15 Reference: B-7 Accounting Changes and Issues, pages 1-6

a) Please provide the evidence Terasen filed with the Board regarding the proposal to build the Coastal Facilities.

Response:

Please refer to Appendix A which contains the BCUC Order C-14-98 approving the Coastal Facilities Project.

b) Please provide the material Terasen filed on August 16, 2004.

Response:

Please refer to Appendix B

c) Please provide the details to the customer benefits claimed by Terasen of $6 million, as the facilities have been fully financed through a synthetic lease.

Response:

If the coastal facilities project was financed as regular plant facilities, the company would be required to increase shareholder equity by 33% of the capital additions. Because this was avoided through the synthetic lease arrangement, ratepayers enjoyed the following benefits:

	2000	2001	2002	2003	2004	Total
Mid Year Rate Base	$ 54,490	54,225	53,428	52,365	51,036	
33% of capital structure		17,894	17,631	17,280	16,842	
Revenue Requirement on 33% of Rate Base		2,982	2,652	2,563	2,353	
Large Corporations Tax		220	195	186	156	
Depreciation Expense		1,473	1,309	1,249	1,193	
Interest		2,361	2,327	2,280	2,223	
Total revenue requirement		7,036	6,483	6,278	5,924	
Lease Payments (grossed up for tax)		4,455	5,156	5,035	5,017	
Total Revenue Requirement Saved		**$ 2,582**	**$ 1,327**	**$ 1,243**	**$ 907**	**$ 6,059**

d) *Please provide a table illustrating the amount paid by ratepayers for the synthetic lease since its inception. What amount of this synthetic lease expense was in effect a return to shareholders?*

Response:

The following table depicts the total payments made to the Coastal Facilities Trust since its inception. Terasen can confirm that none of the synthetic lease expense was a return to shareholders.

($000)	2001	2002	2003	2004	Total
Lease Payments	4,028	4,492	4,424	4,457	17,401

e) *Please provide a table illustrating the original cost the Coastal Facilities and the CCA deductions (Depreciation expense) since the inception of the lease. Does the $50.30 amount provided in the illustration tables represent the depreciated value of the Coastal Facilities?*

Response:

The following table illustrates the original cost of the Coastal Facilities Project less the principal repayments since its inception. The $50.3 million amount represents the depreciated value of the Coastal Facilities.

	2000	2001	2002	2003	2004	2005
Principal - FOY	$ 54,490 *	54,490	53,959	52,896	51,833	50,238
Lease Payment - principal portion	0	(531)	(1,063)	(1,063)	(1,595)	
Principal - EOY	$ 54,490	$ 53,959	$ 52,896	$ 51,833	$ 50,238	

Note: Represent total costs of the project *f) Please provide evidence that investors and credit rating agencies would find 100% debt financing to be a signal of trouble.*

Response:

In general, a company with higher leverage is considered to be exposed to higher cash flow risk. In its Terasen Gas Credit Rating report published on October 1, 2003, Standard & Poor's indicates that "Terasen's deemed equity levels (33% at Terasen Gas and 35% at TGVI) and allowed ROE (9.4% and 9.92%, respectively) are considered low and are substantially lower than those of its global peers." Although recognizing that the cash flows from the pipelines and natural gas distribution business should be stable, the report is concerned that "stability alone does not completely offset the risk of high leverage and weak cash flow protection measures."

Since the equity level is already considered low among its peers, any project with 100% debt financing which increase Company's leverage, will raise concerns for investors and credit rating agencies.

Question: 16 Reference: B-7 Accounting Changes and Issues, page 7-8

a) Please provide a table illustrating the impact to the 2005 revenue requirement if the interest free status is maintained for the total customer security deposits vs. the Terasen Gas recommended approach.

Response:

The anticipated 2005 interest cost related to customer security is estimated to be $517,000

b) What is the rationale for customers receiving prime interest rate minus 2%?

Response:

BC Hydro – Gas Division (the predecessor company to Terasen Gas), paid interest on customer security deposit at simple interest equivalent to one to two year term deposits at rates as set on January 1 and July 1 of each year. In the 1994 phase B rate design proceeding of BC Gas, the general terms and conditions of the BC Gas tariffs were changed, with the approval of the BCUC, to prime minus 2%. It is not known precisely why the switch to prime minus 2% occurred other than perhaps to accommodate the most current interest rates more often than twice a year.

c) What is the interest rate paid by other LDCs on customer security deposit to customers?

Response:

A comparison of the rates paid by local distribution companies are as follows:

- *Terasen Gas (Vancouver Island) currently pays savings account interest rate employed by the Company's principal bank which is currently at 0.25%.*
- *Terasen Gas (Squamish) currently pays the savings account rate which is currently at 0.25%.*
- *B.C. Hydro pays simple interest equivalent to one to two year term deposits rate of the same amount of the security deposit. The current one year savings deposit rate is approximately 2.5% or very close to prime minus 2%.*

d) Please provide a table that indicates which rate classes are responsible for generating the customer security deposit amount that equals about $23 million.

Response:

The majority of the customer security deposits are collected from the residential customer class. The table below provides the details:

	($ Million)
Residential	15.0
Commercial	6.5
Industrial	1.5
Total	23.0

e) Historically, beyond the 9 months in 2004, has the short-term debt financing costs been more then the rate paid on security deposits to customers?

Response:

Historically, the short term debt financing costs have always been more than the rate paid on security deposits to customers.

For example, Terasen's 2003 short-term debt financing cost was 3.14%. Average prime rate was 4.69%. Rate paid on customer security deposits would have been 2.69% or 0.45% lower than Terasen's short-term debt cost.

f) How is the short-term debt financing expense allocated to each rate class? Please provide a table with the percentage allocation by rate class.

Response:

Interest expense is one part of the earned return that is calculated on the utility's Rate Base. In the Company's Fully Distributed Cost Studies (also referred to as Fully Allocated Cost of Service Studies) that were filed as part of the Company's Rate Design Application, the earned return was allocated proportional to the allocation of the Rate Base. The Rate Base has, generally, been allocated in the following manner:

- *Local Storage (Tilbury LNG Plant) allocated to Residential, Commercial, General Firm Service and NGV based on load factor adjusted volumes.*
- *Transmission Plant is allocated to all customers based on load factor adjusted volumes.*
- *Distribution Plant capacity-related costs are allocated to customers served from the Distribution system based on load factor adjusted volumes.*
- *Distribution Plant customer-related costs are allocated to all customers based on a weighted number of customers. The weighting factors take into consideration larger customers, generally, require more expensive service line and metering equipment than a residential customer.*
- *General plant is allocated in proportion to the sum of the above plant items.*

To the extent a cost can be specifically identified to a customer or rate class, the cost is directly assigned to that rate class. For example, the Byron Creek lateral is tracked and allocated directly to Fording Coal – Coal Mountain.

A cost allocation study has not been done for the annual review, so it is not possible to provide a table showing the allocation of interest expense.

Question: 17 Reference: B-7 Accounting Changes and Issues, page 9

a) Please list the accounts that are treated differently from the General Accepted Accounting Principles due to rate regulation.

Response:

A comprehensive assessment of disclosure requirements is scheduled for later this year. In general terms regulatory agencies set rates so that the regulated business may generate revenues which will approximate these allowable costs. Because of specific accounting requirements demanded by regulators, however, some allowable costs may be included in a period other than the period in which the costs would be charged to expense by an unregulated company. In other words, regulators often require capitalization or deferral of expenditures that would normally be expensed in the current period by a non-regulated company following GAAP. Thus, the accounting practices prescribed by the regulatory body often differ from GAAP, with most differences attributable to requirements unique to the rate-making process.

Below is a list of the significance accounts but is not intended to be comprehensive list:

- As mentioned above regulated deferred charges are treated differently from GAAP, the full list of deferred charges are listed in section A tab 3 page 11-11.3. Significant accounts being the rate stabilizations accounts and other post employment benefits.
- Income tax expense that is based on the taxes payable method and therefore rates do not include the recovery of future income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes.
- Property, Plant & equipment - Depreciation and overhead capitalized at rates approved by the BCUC. Cost of depreciable plant retired, together with removal cost less salvage is charge to accumulated depreciation with no gain or loss reflected in income.

b) Does Terasen view this to be a significant issue for the future?

Response:

The current accounting guideline only addresses disclosure requirements as interim measure. The movement toward consistency in financial reporting among regulated and non-regulated entities may have impact on the financial statements of regulated enterprises, if economic realities of the regulating process are not property reported. The regulatory accounting requirements which differ from GAAP often have an impact on the regulated company's financial statements. This significance will depend on the requirements of the proposed new accounting standard to be issued in future by the Accounting Standards Board.

Question: 18 Reference: B-8 Miscellaneous Information

a) Please provide the Commission letter dated February 23, 2004 acknowledging that the 2004 anticipated increases to gross Core Market Administration Expense for Terasen Gas would be offset by Energy Management Services (EMS) revenue.

Response:

Please see Appendix C

b) Please confirm that Terasen is not proposing it shareholders pay half of the cost associated with the Core Market Administration Expense, or half of the additional cost forecasted for 2005 over the 2004 Gross Core Market Administration Expense.

Response:

Terasen Gas is not proposing that shareholders pay half of the cost associated with the Core Market Administration Expense. Nor is Terasen Gas proposing that shareholders pay half of the additional cost forecasted for 2005.

c) Are there any functions that the Core Market Administrative staff provides as Gas Supply EMS services to third parties which Terasen does not use? In addition, has there ever been a case whereby a third party as sought services that are different to the activities this group provides to Terasen?

Response:

No, Gas Supply EMS services are a subset of the services which Terasen Gas uses.

No, third parties have only asked for services which match the activities performed for Terasen Gas.

d) *What is the cost of acquiring the gas supply management function in the open market for Terasen?*

Response:

The projected 2005 cost of service for Gas Supply EMS services is $135,000. This amount is deducted from gross revenue before a net revenue amount available for sharing is determined.

e) *Please provide the rationale for the significant decline in the projected core market EMS revenue recovery offset expected in the 2005 Budget ($70,000) compared to the amount the Commission approved in 2004 ($131,000).*

Response:

Some revenue opportunities in 2004 are not carrying forward into 2005.

Gas Supply EMS contracts negotiated and signed by clients for 2005 gas year services result in a gross Gas Supply EMS revenue of $274,200. When Gas Supply EMS Cost of Service (COS) of $135, 000 is deducted, this leaves net Gas Supply EMS revenue of $169,200. Under the proposed 50/50 sharing the offset to core would be a credit of $70,000.

New Gas Supply EMS revenue opportunities are being pursued. If new Gas Supply EMS opportunities arise through the year the proportionate Core Market share would be offset against Core market costs thus reducing core costs for customers.

f) *Please provide the actual Core Market EMS revenue for the last 3 years.*

Response:

	2002	*2003*	*2004*
Net Gas Supply EMS Revenues	*$0*	*$101,304*	*$131,000*

g) *Given the further increased funding in 2005, please comment on why the Projected core market EMS revenue recovery for 2005 isn't improving?*

Response:

The request for increased funding is for providing regular gas supply functions to the Terasen Gas companies (TGI, TGVI, TGW and TGS) and not for the sales activities associated with the capture of new Gas Supply EMS revenue.

Question: 19 Reference: B-8 Miscellaneous Information, Exogenous Factors, pages 18-19

a) *Does the 2005 Budget cost of $421,000 reflect the incremental cost between the "Bare" annual certification costs vs. the "Full" certification costs?*

Response:

The overall budget is prepared to reflect the estimated incremental cost to perform the work that will allow us to comply with MI52-109. There is not a breakdown between "Bare" and "Full" certification as MI52-109 does not allow for an option – rather it's timing recognizing the efforts required to comply with "Full" certification.

b) *Please provide the detailed difference between "Bare" certification vs. "Full" certification.*

Response:

For "bare" certification (fiscal periods ending before December 30, 2005), MI52-109 requires the chief executive officer ("CEO") and chief financial officer ("CFO") to certify that:

- Interim and annual filings do not contain a misrepresentation or omission of material fact; and,
- Disclosures in interim and annual filings fairly present the financial condition (not to be qualified by the phrase "in accordance with GAAP"), results of operations, and cash flows for the relevant time period.

For "full" certification (fiscal periods ending after June 30, 2006), MI52-109 requires the CEO and CFO to certify that:

- Interim and annual filings do not contain a misrepresentation or omission of material fact;
- Disclosures in interim and annual filings fairly present the financial condition (not to be qualified by the phrase "in accordance with GAAP"), results of operations, and cash flows for the relevant time period;
- Certifying officers have responsibility for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting;
- Certifying officers have designed, or supervised the design, of disclosure controls and procedures to provide reasonable assurance that material information is made known to them;
- Certifying officers have designed, or supervised the design, of internal control over financial reporting to provide reasonable assurance regarding the

reliability and preparation of the financial statements in accordance with GAAP;

- On an annual basis, certifying officers have evaluated the effectiveness of disclosure controls and procedures and have disclosed the conclusions about the effectiveness of disclosure controls and procedures; and,
- Material changes in internal control over financial reporting that occurred during the period have been disclosed.

c) *Please provide a table outlining the actual cost spent to-date 2004, associated with the OSC compliance.*

Response:

The actual costs recorded in Terasen Gas.:	
Incremental costs from Terasen Inc (as of Sept)	142 k
Internal resourcing at Terasen Gas	11k

d) *Please provide an explanation for the incremental internal costs in the 2004 and 2005 Budgets. What is the rationale for the $212,000 Resourcing budget in 2005?*

Response:

As mentioned in 19(f) incremental activities are required to meet project objectives. Additional resources are required to be able to perform these activities. The incremental resourcing of $212K reflected in the schedule is comprised of: incremental Internal Audit staffing (new hire pending at Inc.) = $125K (fully-Certification analyst at Inc.) = $125K (fully-loaded) @ 50% allocation to Gas per agreed methodology = $62.5K, Incremental internal resourcing at Terasen Gas at $87K.

e) *How did Terasen calculate the Contingency amounts for 2004 and 2005?*

Response:

The project budget was estimated upfront and seeing that this is a multi year project and based on assumption & facts at that time the budget includes contingency amounts of 5%.

f) *Given that the establishment of financial statements and audits are part of existing operations of Terasen, please discuss the why there is such a significant cost increase to meet the M152-109 requirements. How can intervenors be assured that the costs noted are incremental costs specifically for the M152-109 requirement?*

Response:

The requirements under MI52-109 impose a significant regulatory requirement and, as such, it is critical that Terasen Gas achieve timely compliance. The project will be a lengthy and comprehensive evaluation of the Terasen Gas's internal control processes.

It is anticipated that the work will involve:

- Conducting an assessment of the entity level controls at Terasen Gas based on the COSO framework;
- Conducting an assessment of the information technology control environment at Terasen Gas;
- Support the development and implementation of a representation / sub-certification process for Terasen Gas;
- Support the formulating and building of the policy and procedures for a Disclosure Committee for Terasen Gas;
- Defining an appropriate level of materiality for the Project, upon which Project deliverables will be based;
- Identifying in-scope locations for documenting financial reporting internal controls at Terasen Gas;
- Conducting a scoping exercise which identifies the key disclosures and their related processes and key financial reporting processes within Terasen Gas;
- Documenting identified disclosure and financial reporting processes;
- Determining appropriate control objectives within each of the identified processes;
- Identifying key controls to achieve established control objectives;
- Identifying weaknesses in the design of key controls;
- Developing remediation plans to improve the design of key controls, if applicable;
- Assessing the effectiveness of key disclosure and financial reporting controls;
- Identifying weaknesses in the effectiveness of the key disclosure and financial reporting controls;
- Developing remediation plans to improve the effectiveness of key controls, if applicable; and,
- Developing a certification sustainment process for Terasen Gas, including the deployment of an assisting technology, which will supports future certification efforts.

A project manager is performing the day to day management of the project including coordination of resources and tasks, project budget, monitoring of project progress, and review of deliverables. As part of this process, the project manager will provide updates of project progress, observations, and relevant issues (e.g. potential disconnects, accountability / alignment concerns, resourcing issues, project budget) to the project steering committee in a timely manner.

Question: 20 Reference: B-8 Miscellaneous Information, Exogenous Factors, pages 20

a) *How are the BCUC levies allocated among the various regulated companies?*

Response:

The BCUC levies are allocated among each public utility based on its total gross energy sales volume. The methodology was established by the Utilities Commission and the calculation is done by BCUC staff. Terasen Gas simply receives quarterly invoices from the Commission outlining the amount due.

b) *In the event, the BCUC allocates a lower levy to Terasen during the remaining PBR period (i.e., 2005, 2006, and 2007) will the company be providing customers a refund associated with the lower amount? In effect, is Terasen of the view the BCUC levies are outside the PBR framework and should be treated as a deferral account item?*

Response:

TGI proposes to treat forecast variance of BCUC levies as a deferral account item commencing 2004. Should the BCUC levies decrease during the remaining PBR period, the forecast variance will be refunded to the customers.

c) *Please provide the BCUC levies allocated to Terasen for the last 5 years.*

Response:

The BCUC levies allocated to Terasen Gas for the last five years are as following (all in thousands):

2000	$909
2001	973
2002	1,062
2003 *	1,124
2004	1,565

* lower by $395 due to credit carried forward from last year per BCUC levy calculation worksheet

Appendix A

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CANADA

BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER C-14-98

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by BC Gas Utility Ltd.
for a Certificate of Public Convenience and Necessity
for the Construction of New Buildings for its Coastal Operations
known as the 1998 Coastal Facilities Project

BEFORE: P. Ostergaard, Chair)
F.C. Leighton, Commissioner) September 3, 1998
K.L. Hall, Commissioner)

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. In its August 5, 1992 Decision on Revenue Requirements the Commission directed BC Gas Utility Ltd. ("BC Gas") to remedy certain safety concerns in its Lochburn facility, to pursue cost recovery from British Columbia Hydro and Power Authority ("B.C. Hydro") and others, and to apply for a Certificate of Public Convenience and Necessity ("CPCN") for any new structures; and

B. On February 17, 1993, pursuant to Section 51 of the Utilities Commission Act, R.S.B.C. 1980, c. 60, as amended, BC Gas applied to the Commission for a CPCN to construct new buildings at its Lochburn and Fraser Valley operating centres in the Lower Mainland (the "Coastal Facilities Project"); and

C. On December 3, 1993, in response to a review by Commission staff, BC Gas filed supplementary information to its February 17, 1993 CPCN application; and

D. On January 18, 1994, in response to a January 7, 1994 application from BC Gas, the Commission approved the BC Gas plans for the temporary relocation of Lochburn employees housed in unsafe buildings, but advised that the costs and accounting treatment for the relocation plans would be addressed in the Commission's decision on the CPCN application; and

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
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E. On June 16, 1994, in its Phase 1 Decision for BC Gas' 1994/95 Revenue Requirements, the Commission identified that its approval of the negotiated settlement for rate base items was exclusive of the Coastal Facilities Project; and

F. On October 6, 1994, in response to a September 13, 1994 application from BC Gas, the Commission advised BC Gas that it did not expect the company to pursue cost recovery from B.C. Hydro and others; and

G. On March 21, 1995, BC Gas again applied to the Commission for a CPCN for the Coastal Facilities Project and withdrew all previous applications; and

H. On March 24, 1995, the Commission issued a letter to those parties who had previously registered as intervenors in the BC Gas 1994/95 Revenue Requirements Review, requesting that they submit comments on the March 21, 1995 application to the Commission by May 1, 1995; and

I. On May 25, 1995 the Commission, by Order No. C-6-95, granted a CPCN to BC Gas to construct new coastal facilities in accordance with the March 21, 1995 application; and

Order No. C-6-95 also approved relocation costs of approximately $4.8 million, consistent with the January 7, 1994 application, and directed that these costs should be recorded in a deferral account and amortized over a period of five years commencing in 1996; and

K. In response to a June 3, 1997 request from BC Gas to review its facility plans, the Commission, on June 12, 1997 by Order No. G-65-97, approved a deferral account to record up to $380,000 of expenditures required to develop cost estimates for a revised Coastal Facilities Project; and

L. Order No. G-65-97 also rescinded the CPCN granted to BC Gas by Order No. C-6-95; and

M. On August 20, 1998, BC Gas filed an application, pursuant to Section 45 of the Utilities Commission Act, R.S.B.C. 1996, Chapter 473 (the "Act"), for a CPCN for the 1998 Coastal Facilities Project (the "Project"); and

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UTILITIES COMMISSION

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NUMBER C-14-98

N. The August 20, 1998 application and supporting material show that the Project will not require all of the land that BC Gas holds at Lochburn and that the surplus land will be sold, with 80 percent of the sale proceeds used to mitigate the net book value of the buildings that are removed; and

O. The Commission has reviewed the August 20, 1998 application and finds that approval of the Project is necessary and in the public interest.

NOW THEREFORE the Commission orders as follows:

1. Pursuant to Section 45 of the Act a CPCN is granted to BC Gas to construct the 1998 Coastal Facilities Project in accordance with its August 20, 1998 application.

2. Prior to starting construction BC Gas is directed to file an updated cost estimate that is based on the detailed design for the Project.

3. During construction BC Gas is to file with the Commission monthly progress reports on the Project schedule and costs, followed by a Final Report upon Project completion. The Final Report is to include a report on the sale of surplus land associated with the Project and the disposition of the proceeds from such sales.

4. The Commission approves the sale of surplus land at Lochburn providing the net proceeds are used for the benefit of utility ratepayers. If BC Gas proposes to credit less than 100 percent of the net proceeds of the land sales to utility ratepayers, it is directed to request and justify Commission approval for its proposed course of action.

5. The Commission approves BC Gas' request to finance the Project using a "synthetic" lease arrangement and to include the costs of the lease in the Utility's cost of service line item that includes other leases. The Commission confirms that Company shareholders will be protected from the impact of changes to current accounting and tax rules, to the extent that the impacts cannot be mitigated, during the term of the financing. The Commission also confirms that if it is not feasible to renew the lease arrangement, the outstanding costs of the Project may be financed as a traditional rate base item.

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER C-14-98

6. The reporting formats for all filings required by this Order are to be established in consultation with Commission staff.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of September, 1998.

BY ORDER

Peter Ostergaard
Peter Ostergaard
Chair

Appendix B

Terasen Gas

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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August 16, 2004

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

Attention: R.J. Pellatt, Commission Secretary

Dear Sir:

RE: Terasen Gas Inc. ("Terasen Gas" or the "Company")
Coastal Facilities Project – Variable Interest Entity

In June 2003, the Accounting Standards Board of the CICA issued a new Accounting Guideline AcG-15 which mandated the Consolidation of Variable Interest Entities and amended it in January 2004 to provide harmonization with corresponding Financial Accounting Standards Board (FASB) Interpretation No. 46 (FIN 46). In September 2003, under AcG-15, the effective date of mandating the Consolidation of Variable Interest Entities was revised from January 1, 2004 to January 1, 2005. As a result of this accounting change, it is necessary for Terasen Gas to change the treatment of the Coastal Facilities assets from an operating lease to an asset to be included in rate base effective January 1, 2005.

Terasen Gas hereby requests treatment in accordance with BCUC Order Number C-14-98 which confirms that if it is not feasible to renew the lease arrangement due to the accounting change, the outstanding costs of the Coastal Facilities Project may be financed as a traditional rate base item.

By way of background, when the Coastal Facilities lease was established, it was financed outside of rate base with 100% debt within the synthetic lease because the debt would not appear on Terasen Gas' balance sheet and therefore the debt ratio, reported in Terasen Gas' financial statements, would be preserved. To accomplish this, BCG Coastal Facilities Trust (the "Trust") was set up to facilitate the synthetic lease arrangement. In order to finance the project with 100% debt, the Trust entered into interest rate swap agreements maturing on November 30, 2007. This arrangement generated significant customer benefits with minimal impact to Company shareholders.

In accordance with BCUC Order No. C-14-98 which confirms that the Company shareholders will be protected from the impact of the changes to the current accounting and tax rules, Terasen Gas proposes to unwind the Coastal Facilities synthetic lease effective January 1, 2005. Terasen Gas recommends the following strategies which offer the least cost impact to customers:

- Terasen Gas assumes the existing interest rate swap arrangement from the Trust effective January 1, 2005. The interest swap agreements were entered into at interest rates that were higher than the prevailing interest rates. As a result, if the interest rate swaps were unwound along with the synthetic lease arrangement, a one-time payment of about $3.2 million would be required in order to unwind these swaps. Terasen Gas' assumption of the rate swap arrangement will result in the avoidance of this up-front payment and associated transaction costs.

- Terasen Gas funds the Coastal Facilities assets with a conventional mix of 67% debt and 33% equity. As the cost of debt in the synthetic lease is approximately 6.7%, Terasen Gas intends to refinance through the issuance of conventional debt at a lower probable rate of 6.1% (including assumption of the interest rate swaps referred to above), providing an estimated annual cost savings of approximately $200,000 for customers. The savings will be reduced somewhat by one-time legal and other related fees associated with the termination of the synthetic lease.

- Terasen Gas transfers to rate base at January 1, 2005 an estimated $50.3 million representing the outstanding balance of the Coastal Facilities Project. Terasen Gas proposes to calculate the depreciation of the Coastal Facilities assets at the prescribed BCUC depreciation rate of 1.5%, commencing in 2005.

As a result of the unwinding of the Coastal Facilities lease structure and the implementation of the above strategies, Terasen Gas anticipates the 2005 revenue requirement to increase by approximately $1.1 million (Appendix A).

We ask that the Commission kindly review the above proposal and advise of its decision before October 1, 2004 in order that such decision is properly incorporated into the Company's Annual Review advanced materials.

We trust the Commission will find the Coastal Facilities Project treatment proposal to be in order; however, should further information be required, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed by:

Scott Thomson

Enclosure

Appendix A

Terasen Gas Inc.
Revenue Requirement Impact of Coastal Facilities Accounting Change

			2005 Revenue Requirement ($000)
Rate Base and Return Impact of the $50.3 million Capital Cost			
Debt ($49.0 million X 6.15% + $1.3 million X 4%)	$	3,066	
Avoided Short-Term Debt ($16.6 million X 4%)		(664)	
Common Equity ($16.6 million X 9.15% / (1 - 34.5%))		2,319	$ 4,720
Depreciation on Buildings ($50.3 million X 1.5% / (1 - 34.5%))			1,152
Large Corporation Tax ($50.3 million X 0.175% / (1 - 34.5%))			134
Avoided Operating Lease Payments ($3,331 + [$1,063 / (1-34.5%)])			(4,954)
Total			**$ 1,053**

Appendix C

ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
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BRITISH COLUMBIA UTILITIES COMMISSION

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Log No. 5091

VIA E-MAIL
Regulatory.Affairs@terasen.com

February 23, 2004

Mr. Scott Thomson
Vice President, Finance and Regulatory Affairs
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C. V3S 2X7

Dear Mr. Thomson:

Terasen Gas Inc.
Core Market Administration Expense for 2004

In response to your letter dated January 21, 2004 and clarifying telephone discussion (the "Application"), the enclosed Commission Order No. G-19-04 approves for Terasen Gas a net Core Market Administration Expense of $1.6 million for 2004. Although Terasen Gas' December 8, 2003 filing anticipated that $76,000 of Core Market Administration Expense would be allocated in 2004 to the Commercial Commodity Unbundling Deferral Account that was approved by Order No. G-57-03, approval of the Core Market Administration Expense of $1.6 million is on the basis that no such allocation will be made to the unbundling deferral account.

Increases to gross Core Market Administration Expense in 2004 will be offset by revenue from providing Gas Management Services to Terasen Gas (Vancouver Island) Inc. and Pacific Northern Gas Ltd. ("PNG"). The Energy Management Services agreement with PNG was accepted by Order No. E-6-03, and the Commission expects that similar arrangements with other parties will be submitted for review by the Commission.

In the Application and related filings, Terasen Gas stated that the increase in gross Core Market Administration Expense in 2004 is due in part to new computer systems that it is acquiring, including a resource optimizing system to replace its current Resources Optimization Model ("ROM"). Recalling the concerns about lack of transparency of ROM during the Southern Crossing Pipeline hearings, and since the new optimizing model will likely be used to support future Resource Plans and other filings, Terasen Gas should ensure that the model can be made available to the Commission and interested parties for examination in future proceedings.

Yours truly,

Robert J. Pellatt

JBW/mmc
Enclosure
cc: Registered Intervenors
2003 Annual Review; Commodity Unbundling Phase 1

TGI/Cor/Core Market Admin Expense

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas Inc.
for Approval of 2004 Core Market Administration Expense

BEFORE: L.A. Boychuk, Commissioner)
L.F. Kelsey, Commissioner) February 19, 2004

O R D E R

WHEREAS:

A. The Commission's February 4, 2003 BC Gas Utility Ltd. 2003 Revenue Requirement Decision approved a net Core Market Administration Expense of $1.6 million for 2003. The gross Core Market Administration expense for 2003 was forecast at $1.7 million, to be offset by $100,000 for gas management services provided to Centra Gas (British Columbia) Inc. [now Terasen Gas (Vancouver Island) Inc.]; and

B. In response to the December 5, 2003 Gas Cost Flow-through Application from Terasen Gas Inc. ("Terasen Gas"), Commission Order No. G-82-03 accepted a Core Market Administration Expense of $1,584,000 for the purpose of forecasting gas costs for 2004, and stated that the Commission will determine the approved Core Market Administration Expense for 2004 based on further filings; and

C. On December 8, 2003, Terasen Gas requested Commission approval of a gross Core Market Administration Expense of $1.831 million for 2004 and an Energy Management Services sharing incentive; and

D. On January 21, 2004, Terasen Gas requested approval to withdraw the December 8, 2003 application and stated that it will submit the matter for review at the 2004 Annual Review; and

E. Terasen Gas verbally confirmed that it requests that the net Core Market Administration Expense continue at $1.6 million per year for 2004; and

. . ./2

F. The Commission considers that a Core Market Administration Expense should be established for 2004.

NOW THEREFORE pursuant to Section 60 of the Utilities Commission Act, the Commission approves a net Core Market Administration Expense of $1.6 million for 2004 for Terasen Gas.

Terasen Gas is directed to file an application with respect to the Core Market Administration Expense for 2005 for consideration in the 2004 Annual Review.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of February 2004.

BY ORDER

Lori Ann Boychuk
Commissioner