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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-51-03

TELEPHONE: (604) 660-4700
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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.
(formerly known as BC Gas Utility Ltd.)
for Approval of a Multi-Year Performance-Based Rate Plan
to Set Rates for 2004-2008

BEFORE: P. Ostergaard, Chair)
R.H. Hobbs, Commissioner) July 29, 2003
R.D. Deane, Commissioner)

O R D E R

WHEREAS:

A. In accordance with the determinations from the 2003 Revenue Requirements Decision dated February 4, 2003, Terasen Gas Inc. (formerly BC Gas Utility Ltd.) ("Terasen Gas") applied to the Commission on April 17, 2003 for approval of its Multi-Year Performance-Based Rate Plan to set rates for 2004 to 2008 pursuant to Sections 58 and 61 of the Utilities Commission Act; and

B. Commission Order No. G-29-03 established a timetable for the Negotiated Settlement process which included a Workshop and Pre-hearing Conference on May 15, 2003, followed by Information Requests and Responses; and

C. Negotiations commenced June 9, 2003 and a proposed Settlement Agreement for a 2004-2007 Performance-Based Rate Plan was reached by Terasen Gas, a group of Intervenors and Commission staff; and

D. The Lower Mainland Large Gas Users Association, the Heating Ventilating Cooling Industry Association of B.C., the B.C. Greenhouse Growers Association, the United Flower Growers Co-operative Association and Avista Energy Canada Ltd. filed concerns dissenting from the Settlement Agreement but stated that they were not asking for further public process; and

E. The Commission has reviewed the proposed Settlement Agreement and considers that approval is in the public interest.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves for Terasen Gas the Settlement Agreement for a 2004-2007 Performance-Based Rate Plan, attached as Appendix A.

2. In accordance with the 2003 Revenue Requirements Decision, and by October 31, 2003, Terasen Gas is directed to provide to the Commission a plan for the separation of Terasen Inc. pensions, salaries and expenses.

3. It is open to the parties to pursue any concerns regarding the Terasen Gas Code of Conduct, Transfer Pricing Policy, and Website by way of the Customer Advisory Council forum established by the Settlement Agreement or by the complaint process pursuant to Section 83 of the Utilities Commission Act.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of July 2003.

BY ORDER

Original signed by:

Robert Hobbs
Commissioner

Attachment

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Multi-Year Performance Based Rate Plan for 2004-2007
Terasen Gas Inc.

Negotiated Settlement

Terasen Gas Inc. “Terasen Gas”, (formerly BC Gas Utility Ltd.) filed an Application relating to its 2003 revenue requirements and a multi-year PBR in June 2002 that requested that the Commission establish a process for achieving a negotiated settlement of both the 2003 revenue requirements and a multi-year PBR. Commission Order G-63-02 contemplated a two step process for the consideration of the Company’s Application for a multi-year PBR. The Order indicated that a full public review of the costs incorporated in the base year rates would be supportive of more efficient negotiated settlement discussions regarding the multi-year PBR. A public hearing was held commencing November 12th, 2002 and the Commission’s Decision was issued February 4, 2003. That Decision reviewed the Company’s costs and revenues, and established rates for 2003.

The need to proceed in a timely manner with the second step of the process for establishing the multi-PBR was reinforced in the Commission’s Decision. The Decision stated:

> “The Commission anticipates that BC Gas will file, early in 2003, a multi-year PBR Application for revenue requirements for 2004 and beyond which incorporates the determinations made in this Decision.”

The Company filed its multi-year PBR Application on April 17, 2003. The Commission issued orders G-29-03 and G-38-03 that set out the timetable for the Negotiated Settlement process which included a Workshop and Pre-Hearing Conference on May 15, 2003 followed by the submission of Information Requests by interested parties and responses by the Company. Negotiations commenced June 9, 2003 and these negotiations led to the settlement terms included in this document and its appendices.

Terasen Gas and a group of Intervenors reached this Negotiated Settlement of a Multi-Year Performance Based Rate Plan for the years 2004 through 2007. This Settlement document describes the agreed terms and conditions for the Company’s multi-year performance based rate plan and includes a number of detailed appendices that together form the settlement agreement:

- Appendix 1 – a comprehensive listing of issues dealt with in the Terasen Gas application and a number of additional issues that arose during negotiations and their resolution. That document is intended to provide further details of the Settlement and to assist the Commission and all participants by identifying the relevant sections of the Application and Information Responses with respect to each issue, so that any party may review the filed material to understand the resolution achieved.
- Appendix 2 – the details of an expanded annual review process
- Appendix 3 – a description of the capital expenditures true-up process and the end-of-term capital benefit phase-out mechanism

The parties supporting this settlement include the B.C. Health Services, Elk Valley Coal Corporation, the Inland Industrial Group, and the British Columbia Old Age Pensioners Association et al. The representative on behalf of the Lower Mainland Large Gas Users Association, the United Flower Growers Association, the B.C. Greenhouse Growers Association, Heating Ventilating Cooling Industry of B.C. and Avista Energy Canada Ltd., was unable to agree with certain aspects of the settlement document.

A major issue in the negotiations was the proposed term of the agreement. The four-year term commencing January 1, 2004 is one year longer than previous settlements with BC Gas or Aquila. Net restructuring costs incurred after July 1, 2003 will be included in 2004 costs. A key factor in extending the term of this agreement is the expanded annual review process detailed in Appendix 2. The new annual review process will require Terasen Gas to provide considerable information on its current and future year activities, along with statistics on its quality of service provided and its compliance with the code of conduct and transfer pricing policy. The parties agreed that Terasen Gas is responsible for all management and operating decisions of the Company. This settlement and its provisions to provide operating information at annual reviews do not provide for the pre-approval of operating decisions by the parties, ie. no micro-management.

In agreeing to the extended term of this settlement the parties also recognize that the PBR Plan includes other features to reduce the risk of undesirable outcomes, including a mid-term assessment review in year 3, a "trigger mechanism" to review whether the settlement agreement should terminate if the achieved return on equity is greater or less than 150 basis points from the approved level or if there is a serious degradation of SQIs. There is also to be a semi-annual customer advisory council meeting in October prior to the Annual Review and in the following April. The Agreement also includes a "no surprises" term which is to ensure that any significant changes or restructurings at the utility will have been discussed with interested parties.

This PBR Plan has strengthened the incentive for Terasen Gas to control its capital spending on items other than Certificates of Public Convenience and Necessity ("CPCN"). Although the Terasen Gas application included incentives on all capital additions, including CPCNs, the parties agree that CPCN applications should continue to be outside of the incentive formula and approved separately by the Commission. The expected

CPCNs over the term of the agreement, as identified in the Application, are modest in comparison with the substantial projects which were undertaken over the past five years. The base capital will be subject to incentives and productivity requirements as discussed below.

The O & M costs and base capital are subject to an incentive formula reflecting an increasing cost as a result of customer growth and inflation, minus a productivity factor defined as a percentage of inflation. The parties agree to continue to use estimates of inflation based on CPI(BC) as previously undertaken in the last settlement. However, the productivity adjustment has been changed from a discreet value to be 50 percent of CPI(BC) for years 1 and 2 of the settlement and 66 percent of CPI(BC) for years 3 and 4. The parties believe that linking the productivity factor to CPI(BC) will be beneficial for both the ratepayers and the Company since the available productivity will increase as inflation increases and the Company will have limited prospects for productivity if inflation decreases. In particular the existing labour contracts will become a challenge for the Company if inflation falls toward zero. The parties have agreed to a continuation of the 50/50 sharing mechanism of earnings above or below the allowed return on equity, net of incentives. The sharing mechanism creates an alignment between the Company and ratepayers. Net restructuring costs incurred after July 1, 2003 will be included in 2004 costs.

This settlement agreement includes a two-year phase out of the final year capital benefit. The phase out will be two-thirds of the capital benefit in the first additional year and one-third of the final year base capital savings in the second year. This is similar to the treatment of capital variances at the end of the previous 1998/2001 PBR and will maintain the incentive towards achieving efficiency in capital spending throughout the term of the agreement.

Maintaining acceptable levels of service quality is an important aspect of incentive regulation. In this settlement agreement the parties have agreed to an expanded group of ten SQIs, seven of which have specific benchmarks to be achieved and three which will be compared with previous year's results. The agreement also includes two directional indicators. The Company is accountable for its quality of service by reporting on its performance at the annual reviews, with an opportunity for participants to argue to the Commission that Terasen Gas should not be awarded its full financial incentives if the service quality has deteriorated. Participants may also argue to the Commission that the incentive agreement should be terminated if there is a serious degradation of service quality during the term. The details of the service quality indicators are provided in the annual review document (Appendix 2).

Terasen Gas and the participants are interested in incenting the Company to control costs on expenditures which may be only partially controllable by the utility. For example, the parties have agreed to an incentive mechanism with respect to government taxes and fees. In addition Terasen Gas is encouraged to bring forward any new ideas with respect to positive incentives for partially controllable expenses to the annual reviews. The terms of this settlement agreement in Appendix 1 also deal with a number of other technical issues. These include changes to the accounting treatment with respect to transmission pipeline integrity programs ("TPIP") to expense the recurring costs while continuing to capitalize the facility modifications with respect to the integrity program. The settlement agreement also identifies that any changes in regulatory treatment resulting from changes in GAAP will require Commission approval.

Incentives for load building initiatives may be developed and submitted prior to an annual review. The incentive would only apply to initiatives which are determined to be beneficial to ratepayers after a DSM like assessment of each initiative.

During the term of the PBR, the Company may apply to the Commission to undertake restructuring or other efficiency initiatives that require an incentive or payback term extending beyond the term of the PBR agreement. The application would set out the accounting mechanism and the performance/prudence criteria to be used to decide on the ultimate disposition of the incentive account.

At each annual review commencing November 2003, the Company will update its forecast of customer additions, use per account and industrial revenues. The impact on revenues resulting from the updated forecasts will be flowed through in delivery rates in the following year. The settlement also provides for the flow through of the impacts of changes approved by BCUC orders and exogenous factors.

Finally, the currently approved capital structure for Terasen Gas will continue, as will the quarterly reviews of natural gas commodity costs.

For further information on all issues please refer to the settlement terms in Appendix 1.

Attachments

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APPENDIX 1

**Terasen Gas Inc.
PBR Plan 2004-2007
Settlement Terms**

Application 2004-2008 PBR Plan	Resolution
Term Terasen Gas proposes a five year term for the PBR Plan	A four year term from 2004 to 2007 was accepted.
Productivity Page C-25 proposes a results-based adjustment factor of 0.75% each year from 2004-2008 for O&M and Net Gas Plant in Service.	The adjustment factor will be 50% of CPI for 2004 and 2005, and 66% of CPI for 2006 and 2007. See O&M and Capital Additions Forecast sections below.
Inflation CPI (BC) will be used to adjust the controllable expenses as described on page C-10. Rates will be set prospectively, and as in the 1998 plan, the rates will not be modified to reflect actual CPI (BC). CPI (BC) is forecast as 1.8% for 2004 and 2% for 2005-2008 in Section H, Tab 3, page 2.2. The Annual Review will update the inflation forecast for the upcoming year as described in Section H, Tab 9, p. 1 and BCUC IR10.1, but there will be no true up to actual CPI(BC). Alternative inflation indices were discussed in BCUC IR 10.2 and Elk Valley Coal Corporation IR#2, Questions 2-4.	CPI (BC) accepted as filed.
Customer Growth The Annual Review will update the customer count for the actual number of customers at the start of the year and forecast customer growth for the upcoming year as described in page F1 and BCUC IR 9.1.	Accepted as filed-same as 1998-2001 PBR.
Revenues Revenue categories identified on pages C-13 to C-14 include amounts received from sale and delivery of gas, transportation service, revenues received under tariff supplements, $85 from application for service and revenues from account transfers. Revenues will be forecast each year and the company is at risk within the year for variances in industrial revenues, customer additions, applications for service and account transfers. Throughput variances for residential and commercial customers in rates 1, 2 and 3/23 will be subject to RSAM. Variances in Burrard Thermal and SCP revenues will be deferred and amortized. Pages F-1 to F-8 state that the forecast process has a customer additions forecast, an average use per account forecast and an industrial forecast. A 2003 industrial survey will be presented at the 2003 Annual Review. The residential use per account of 108 GJ was used for 2003 and in the	Forecast process is acceptable. Earnings variances relating to at risk revenue items will be included in the Earnings Sharing Mechanism.

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Application for 2004. The use per account for rates 1, 2, 3 and 23 will be reforecast at the 2003 and subsequent Annual Reviews. Other revenues of Centra Gas (PCEC) Wheeling Agreement and SCP third party revenues will be forecast each year at the Annual Review. Late payment revenue will be adjusted to the same formula as O&M expenses. Page C-14 indicates that load-building programs will be brought forward either at or before Annual Reviews. These are separate from DSM programs as confirmed in BCUC IR 7.2	
Gas Cost Section H, Tab 8, p. 1 states that the cost of gas used under the PBR will be based on the approved unit gas costs prevailing at the time the volume and revenue forecast is made. Page C-19 proposes the continuation of GCRA and GSMIP.	Accepted as Filed
O&M Section H, Tab 9, p. 1 proposes that O&M expense for 2004-2008 be determined by a formula-based approach that starts from a base of the 2003 Decision O&M escalated by growth in customers and inflation less an adjustment factor of 0.75%. The O&M formula on Section H, Tab 9, p. 1 is: [Base Cost x(1+Growth) x (1+Inflation-0.75% adjustment factor)] Page C-13 proposes that pension and insurance costs will be forecast each year with variances deferred for flowthrough amortization over one year. Vehicle and Coastal Facilities Lease are added (not part of O&M formula) Pipeline Integrity Costs-if a planned capital expenditure is to be funded through O&M then page C-19 proposes that the allowed O&M be increased.	Accepted for 2004 – 2007 with adjustment factors of 50% CPI in 2004 and 2005, and 66% CPI in 2006 and 2007. Beginning in 2004, ongoing pipeline integrity costs are to be expensed as O&M and a levelized adjustment will be made to the base O&M in the formula for years 2004-2007. Facilities retrofits will continue to be treated as CPCNs throughout the term. See also Capital Additions Forecast.
Overhead Page G-5 proposes a 16% overhead per year from 2004-2008, calculated consistent with the response to BCUC IR 11.1 and Section H Tab 9 Page 2 of the Application.	Accepted as Filed except that the amount of gross O&M not subject to Overheads Capitalized will be escalated by the O&M formula. The amount not subject to overhead capitalization is the sum of $19,373,000 (Section H, Tab 9, Page 2) and the levelized incremental pipeline integrity O&M expenses of $5,505,000.
Net Gas Plant in Service Formula	

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Section H, Tab 3, p. 2 proposes that Mid-year NGPiS for 2004-2008 be determined by a formula-based approach that starts from a base of the 2003 Mid-year NGPiS escalated by growth in customers and inflation less an adjustment factor of 0.75%. The NGPiS formula on Section H, Tab 3, p. 2 is: Current Mid-year NGPiS=(Prior Mid-year NGPiS/customer) x (Forecast Average Number of Customers in Current Year) x (1+Inflation-0.75% adjustment factor) 2003 Mid-year NGPiS is based on actual 2003 opening NGPiS and the projected 2003 year end NGPiS from the fall 2003 Annual Review. Formula-based values of NGPiS, accumulated depreciation, CIAOC, net plant additions are not rebased during the five year PBR.	The Net Gas Plant in Service formula approach was not accepted. See Capital Additions Forecast.
Capital Additions Forecast Section H, Tab 3, pp. 2.2 to 2.4 and BCUC IR 2.2 show gross plant additions are back-calculated in several steps from the formula-based mid-year NGPiS and forecast retirements. Forecast retirements are the same as the amounts in last year's PBR proposal.	<u>Base Capital Expenditures.</u> As per BCUC IR 4.6, use formulas based on customer additions and average number of customers. Using (1+CPI (BC)-Adjustment Factor). Base capital expenditure amounts will not be rebased to actual amounts during the term. For rate setting in subsequent years the formula base capital expenditures from the prior years will be adjusted for projected customer counts and trued up for actual customer counts as this information becomes known. The cumulative difference over the four-year term between the trued-up formula based capital expenditures and actual base capital expenditures will be subject to a phase-out of the benefits of 2/3 in the year after the term and 1/3 in the second year after. An example of the capital true-up process and capital benefits end-of-term phase-out is attached as

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	Appendix 3. <u>Capitalized Overhead</u> 16% of gross O&M calculated by formula, consistent with the response to BCUC IR 11.1 and Section H Tab 9 Page 2 of the Application. The levelized O&M increase for ongoing pipeline integrity program expenditures will not be subject to overheads capitalized. <u>CPCN Additions</u> CPCN expenditures are excluded from the capital formula. Except in very unusual circumstances, CPCNs will not be filed for projects below $5 million. Transmission Pipeline Integrity CPCNs will be limited to retrofits, which BCUC IR 23.2.1 (2003 Revenue Requirement Application) showed as $2.8 million in 2004 and $3.0 million in 2005. CPCN expenditures to be included for rate setting purposes will be only for those projects which have been approved by the Commission and are projected to be in service prior to the year for which rates are being set. The revenue requirement effect of variances between projected and actual CPCN expenditures for those projects being added to rate base will be taken into account in the Earnings Sharing Mechanism.
15% Plant Additions Benefit Factor Appendix C-A-2. p. 2 proposes that the current year plant additions savings (actual versus NGPiS formula) be multiplied by a factor of 15% to represent the average avoided annual revenue requirement. An example is provided in	 Accepted for application only to base capital additions for the end-of-term capital

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BCUC IR 1.9.2 showing a levelized saving of 13.21%. The 15% factor provides for the possibility of plant accounts with higher depreciation rates or higher cost of capital in the future.	benefits phase-out except that the factor should be 14%.
Depreciation Rates Section H, Tab 4 deals with the calculation of depreciation expense for 2004 to 2008. Depreciation rates for Meters, Meter Installations and Regulators and Computer will be adjusted effective January 1, 2004. Under the PBR proposal, the accumulated depreciation used in setting rates each year in the Annual review process will arise from the NGPiS calculation, as described in BCUC IR 2.1. Retirements to be used in the accumulated depreciation calculation will be forecast each year for the Annual Review.	Accepted as Filed.
Restructuring Deferral Account Pages C-15 and C-16 propose that after the PBR Plan is approved, investments in restructuring will be deferred and recovery will commence in 2004 from actual savings before any sharing. If there is a debit balance in the deferral account in 2008 then it is applied against the full term efficiency incentive. 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. In BCUC IR 1.11.5 the Company proposes a non-rate base deferral account. In BCOAPO IR 4.1 the Company proposes that the revenue requirements would not be increased by the amount of the deferral account. In LMLGUA IR 4.1 the Company anticipates that a definition of what is to be included in restructuring costs would be included in the negotiated settlement document. The Company proposed items to be included are in BCUC IR 1.11.1. On page C-15 and in BCUC IR1.11.2 and BCOAPO IR 4.1 and 4.2 the Company states that positive variances from the allowed ROE will first be used to offset the costs included in the restructuring deferral account prior to sharing.	All restructuring costs incurred during the Term are to be treated as normal expenditures. Specific restructuring initiatives requiring longer term recovery or providing longer term benefits beyond the end of the Term can be brought forward by the Company for consideration at any Annual Review. Net restructuring costs incurred by the Company between July 1, 2003 and December 31, 2003 will be captured in a deferral account, to be recovered as a 2004 expense. Net restructuring costs refers to the netting off of savings the Company realizes in 2003 from restructuring activities. The deferral account will be non-interest bearing non-rate base.
Full Term Efficiency Incentive Page C-16 and Appendix C-A-2, pp. 1-4 describe FTEI as motivating new efficiencies and provides for retaining savings for five years after the investment is made to repay the cost of the initial investment before savings are shared with customers.	The FTEI is not accepted. However, there will be a capital benefits phase-out at the end of term as described in the Capital Additions Forecast section above. .

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Sharing Mechanism

Appendix C-A-2, pp. 1-4 describes and provides an example of the sharing mechanism for savings in net O&M, the gross plant additions benefit and industrial revenue variances. The allocation of savings to the Restructuring Deferral Account and the FTEI is also described.

Pages C-15 and C-16 propose that sharing commence on January 1, 2004 with 50/50 sharing of earnings above or below the allowed ROE, net of GSMIP, the DSM Achievement Incentive and other incentives. The customers' portion of the sharing will be projected at Annual Reviews and provided to customers by a rider in the following year. The customers' actual portion of sharing shall be determined after year end and variances from projections provided to customers by a rider in the following year. Sustained (two-year average) return that is 200 basis points above or below the allowed ROE triggers an Off-Ramp review.

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The 50/50 sharing mechanism is accepted based on the difference between the allowed and actual ROE (net of GSMIP, DSM Incentive, load building and incentives for partially controllable items) using the common equity component of the actual rate base.

See Trigger Mechanism.

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Deferred Charges and Amortization

Pages G-6 to G-7 seeks continuation for 2004 to 2008 of:

- Deferred interest account to collect interest expense variances from forecast short-term debt rates and from forecast long term debt rates, principle, timing of issues and long term debt issue costs.
- DSM incentive grants for deferral of grants of up to $1.5 million per year. BCUC IR 7.2 explained that the deferral account would only be used to collect incentive payments and rebates to customers. Costs associated with advertising (including awareness programs), program promotion, program design, administration, research and evaluation would be O&M expenses.

Additional requests:

- Amortize over 5 years commencing in 2005, the deferred 3rd party revenues arising from the cancellation of PG&E contract net of any mitigation revenues received.
- Deferral of variances in pension expense and insurance expense from forecast.
- Deferral of the costs of the PBR Application and amortize over 5 years.

Section H, Tab 3, pp. 6.1 to 6.6 requests the following treatment:

- Deferred interest is amortized over three years.
- Market Rebate Incentive-Water Heater Grants are continued until final year of amortization in 2004.
- NGV Conversion Grants with continued additions as approved by Orders G-98-99 and G-7-03 and five year amortization.
- 2003 Revenue Requirement with five year amortization.
- 2004-2008 Revenue Requirements with accumulation of costs and five year amortization.
- DSM program to continue with expenditures of $1.5 million per year for 2004-2008 and three year amortization.
- DSM-DRIA to continue with three year amortization.
- Property Tax Deferral with continued accumulation of variances between forecast and actual with three year amortization.
- GCRA and GCRA Interest with continued recording of interest on

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Proposed deferral accounts and amortization periods are acceptable.

A DSM assessment report should be provided at the Annual Review of proposed programs for the upcoming year and an analysis of existing programs.

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GCRA variances from forecast. Amortization in accordance with Orders No. G-124-00, G-134-01 and G19-03. • RSAM will continue to accumulate differences between forecast and actual use rate of RSAM customers per year from 2004-2008. Any RSAM additions are amortized over three years. Variances between forecast and actual balances will accumulate short-term finance costs. • BC Hydro Services Agreement Costs with continuation of two year amortization by 2003 Decision and Order G-7-03. • Coastal Facilities with continuation of five year amortization by Order C-14-98. With deferral of costs approved by Order C-14-98 and two year amortization by 2003 Decision and Order G-7-03. • ABC-T Project Requirements Phase with two year continued amortization commencing in 2003 by Order G-24-02. • Burner Tip Service with continued one year amortization by 2003 Decision and Order G-7-03. • Earnings Sharing Mechanism as an amortization of the January to February 2003 refund over the remaining March to December 2003 period by 2003 Decision and Order G-7-03. • Salmon Arm Reinforcement with continued amortization by Order G-26-00. Final year of amortization in 2003. • NGV Compression Equipment Recovery with continued 10 year amortization by Order G-143-99. • 2001 Rate Design with continued amortization over three years starting in 2002 by Order G-116-01. • Overheads Change-Income Tax Refund and CIAOC Software Tax Savings/OH Change with continued amortization over five years by 2003 Decision and Order G-7-03. • Other Post Employment Benefits with continued regulatory accounting treatment by Order G-7-03. • Deferred 2000 SCP Cost of Service with amortization over five years by Orders G-135-99 and G-7-03 and 2003 Decision. • SCP Net Mitigation Revenue and SCP West to East Transmission with continued five year amortization by Orders G-124-00, G-123-01, G-7-03 and 2003 Decision. • SCP PG&E Contract Cancellation with forecast lost revenue per Letter L-48-02 and requested amortization over five years commencing in 2005. • CCT Deferral with continuation of five year amortization starting in 2003 by 2003 Decision and Order G-7-03 of deferred credit recorded by Orders G-85-97 and G-48-00. • CCT Assessment with amortization period of three years by 2003 Decision and Order G-7-03.	

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Working Capital Section H, Tab 5, p. 1 proposes that Gas in Storage and Transmission Linepack and All Other Working Capital will have a revised forecast at the Annual Review. Cash Working Capital will use lead/lag methodology from the 1992 Decision with changes from the 2003 approved lead or lag days currently in rates brought forward each year as necessary. In BCUC IR 11.2 the Company discusses using a formula to calculate cash working capital based on the mid-year NGPiS.	Accepted as filed.
Finance, Accounting and Tax Issues Pages G-1 to G-6 propose: • New long term debt issues of $850 million for 2004-2008 with an expected rate of 7%. A 2003 long-term debt issue of $150 million for 2003. Debt expense to be reforecast at each Annual Review as described on page C-12. • Short term debt rates of 4% for 2004 and 5% for 2005-2008. Debt expense to be reforecast at each Annual Review. • Any changes in GAAP would be treated as flowthrough items. • A report will be filed on the separation of BC Gas Inc. pensions, salaries and expenses from BCGUL. The Corporate Centre is expected to have 40-45 employees. Forecast O&M is consistent with the 2003 Decision and the amounts charged by the corporate Centre to BCGUL will be consistent with the 2003 Decision.	Accepted, but any changes in regulatory treatment resulting from changes in GAAP will require Commission approval.
Regulatory Accounting Methodologies Page C-19 proposes the continuation of GCRA/RSAM accounts, taxes payable method for income taxes, regulatory treatment for CPCNs from the 1998-2001 PBR Plan, accounting for certain assets and rate stabilization accounts on a net of tax basis, accounting for property, plant and equipment to include overhead and AFUDC. Approved depreciation rates are used. The current accounting treatment of property, plant and equipment retirements will continue.	Accepted as Filed.
Taxes Page C-13 proposes a deferral account to record variances in property taxes, income tax rates, LCT rates, and any new government tax expenses, charges and levies. Amortization over three years as a flowthrough item. At the Annual Review a forecast of income tax and LCT rates and other tax expenses for the following year will be provided and customers' rates for that following year will be determined on the basis of that forecast.	Accepted as Filed.
Exogenous Factors Exogenous Factors are described on page C-16 as items beyond the Company's control that will be adjusted in rates (flowthrough). These factors include judicial, legislative or administrative changes, orders or	Accept the arguments of Terasen Gas and accept same practice as 1998-2001 PBR.

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In BCUC IR 1.5, the Company lists the flow through items and exogenous factors and discusses the merits of fixing an expense and allowing the item to be “at risk”. The Company believes that partially controllable items should be evaluated on an item by item basis and considered in the context of the overall PBR.</td><td></td></tr>
<tr><td>Service Quality Indicators

Appendix C-A-1, pp. 7-14 discusses benchmarks for proposed SQIs. Appendix C-A-1, p. 5 proposes a benchmark based, where possible, on a three year history at the beginning of the PBR that is maintained throughout the PBR period.

<u>Proposed SQIs</u> — <u>Benchmark</u>
Response Time to Site for Emergency Calls — 21.1 minutes
% of Responses within 30 Seconds -Emergency — 95%
% of Responses within 30 Seconds-Non-Emerg — 75%
Trans System Annual Reportable Incidents — 2 Reportable/yr
% of Customer Bills Meeting Performance Criteria — Score 5.0 or less
Meter Exchange Appointment Activity — 92.2% met

<u>Directional Indicators</u> — <u>Three Year Average</u>
Number of Third Party Damages — 1,219
Leaks per Kilometre of Distribution Mains — 0.0041

BCUC IR 1.10.7 states whether or not the achievement level for SQIs should be used to qualify the Company for an incentive should be dealt with similar to the 1998-2001 PBR. Page 13 of that PBR stated that SQIs will be reviewed at Annual Reviews and participants can make submissions to the Commission that a deviation from a benchmark is significant enough that it should limit incentive payments to the Utility.</td><td>Refer to the SQI section in the Annual Review document (Appendix 2)</td></tr>
<tr><td>Trigger Mechanism

Page C-18 proposes that a full regulatory review is triggered if the two-year average achieved ROE after sharing exceeds or drops below the allowed ROE by 200 basis points or if there is a serious degradation of Service Quality Indicators. LMLGU IR 21 clarified that the two-year average refers to two consecutive years and in IR 32 the Company expressed the belief that “serious degradation” cannot be defined in a manner that would foresee all circumstances.</td><td>A Commission review of the PBR Plan can be requested by any party if the achieved ROE after earnings sharing varies from the allowed ROE by 150 basis points in any year of the term.</td></tr>
<tr><td>Annual Review

The process for the Annual Review and rate setting for the following year is described in BCUC IR14.1 as being similar to the 1998-2001 PBR as adjusted for 2004-2008 PBR Plan formulas, SQIs, plant additions.</td><td>Expanded 1998-2001 PBR Annual Review process is acceptable. See attached.</td></tr>
</table>

~~**Confidential**~~

No Surprises	Terasen Gas is to advise all parties of any major changes planned for the Utility and nothing in this settlement provides Terasen Gas with any approval to change its business practices to the detriment of customers. For example, the spin off of significant operations, such as those outsourced to CustomerWorks would require disclosure prior to undertaking.
Mid-Term Assessment Review Page C-18 proposes that a review be held prior to the end of the third year (2006). If there are unintended outcomes or deterioration in service quality, the parties can jointly address a cure. LMLGUA IR 12.1 describes the Mid-Term Assessment Review as an expanded Annual Review.	The proposal is acceptable.
Customer Advisory Council (CAC) (This item was not addressed in the Application)	A customer advisory council will be established which meets twice yearly to deal with any customer issues that have arisen during the year. The purpose of the CAC will be to provide a non-binding forum for customer groups and the Company to communicate and deal with customers' concerns constructively and proactively. One of the meetings will be held in advance of the Annual Review to provide an opportunity for customers to raise issues again at the Annual Review which have not been satisfactorily resolved in the CAC process. The Company's representatives on the CAC will comprise of the President, Vice President of Marketing and Vice President of Regulatory Affairs. A record of the meetings will be kept and made available upon request.
Equity Thickness	

~~**Confidential**~~

Page G-1 confirms that the Company finances its assets with a mix of debt and equity following the Commission's approved capital structure of 33% common equity and 67% debt.	The equity component is consistent with the 2003 Decision and is acceptable. This does not preclude the Company from making an application to the Commission for a variation of its equity thickness if appropriate.
Load Building <u>Company proposed incentives around load building initiatives.</u>	 Concept of incentives for load building initiatives accepted, subject to DSM-like assessment (including net present value of expected revenues and costs) of each initiative.
<u>Company proposed framework of specific load building program based on increased penetration for gas cooking, clothes drying and water heating appliances. See attachment. Company may develop other initiatives during the Term.</u>	A DSM-like assessment (including net present value of expected revenues and costs) should be provided at or before Annual Review before initiative starts.

<u>**Other Items**</u>	Resolution
<u>**Partially Controllables**</u> <u>Stakeholders expressed interest in exploring positive incentives around partially controllable expenses. The Company was also interested.</u>	 Company to have a positive incentive around provincial and municipal government taxes, fees and expenses. Details of an incentive respecting property taxes were agreed. See Appendix 5.

~~Confidential~~

	Company or interested parties (intervenors/Commission staff) to bring forward any new ideas around positive incentives for partially controllable expenses to Annual Reviews.

APPENDIX 2

Annual Review of the Terasen Gas 2004 — 2007 PBR Settlement (the Settlement)

Annual Reviews and Rate Adjustments

For each year of the Term of the Settlement, the Commission will conduct an Annual Review with Terasen Gas and interested parties. The Annual Review is a proceeding for purposes of participant cost awards.

The Annual Review has the following objectives:

- To inform the Commission and interested parties about the activities of Terasen Gas;
- To review Terasen Gas performance under the Settlement, including its costs, service levels and future plans;
- To identify any concerns regarding the proposed activities of Terasen Gas for the coming year;
- To attempt to obtain consensus on issues that must be decided by the Commission in advance to set rates for the next year; and
- To determine if there has been any action by Terasen Gas that may justify a reduction in any portion of the Terasen Gas shareholder incentive payments pursuant to the Settlement.

The Annual Review

At the Annual Review to be held in November of each year beginning in 2003 through 2006, Terasen Gas will present projections for the year that is ending and forecasts for the next year. For the year that is ending, Terasen Gas presentation will include projections of the following:

- Utility volumes and revenues;
- Utility expenses;
- Year-end plant balances and other rate base information;
- Deferral account balances and amortization;
- Year-end customers and other cost driver information;
- Utility earnings;
- Material efficiency measures or investments, except where the Commission determines that public disclosure of such information at the Annual Review may harm Terasen Gas business interests and such harm outweighs the public interest in public disclosure; and
- Service Quality Indicator results.

For the next year, Terasen Gas presentation will include forecasts of the following:

- Customer growth;
- Inflation;
- Utility volumes and revenues;
- Utility expenses (determined by the PBR formula plus flow through items);
- Utility capital expenditures (as determined by the PBR formula);
- Plant balances, deferral account balances and amortization to be included in rates;
- Savings and costs of efficiency measures that may materially affect Terasen Gas operations, costs or services, except where the Commission determines that public disclosure of such information at the Annual Review may harm Terasen Gas business interests and such harm outweighs the public interest in public disclosure; and
- Savings and costs of proposed efficiency measures for specific restructuring initiatives requiring recoveries or providing benefits beyond the expiry of the Term.

Cost drivers for the next year will be updated to reflect the most recent forecasts. The customer addition related cost drivers for the next year will also be updated for projected variances between actual customer growth in the past year and the customer growth that had been forecast for that year.

Each year, Terasen Gas will file its updated five-year major capital project plan. The plan will include a system-wide analysis showing the following:

- Peak load projections
- Areas of capacity shortfall
- Projects for system modification or expansion
- Cost projections for regular capital and CPCNs
- Scheduling of projects

The plan will indicate CPCNs that may be needed in future years.

At the Annual Review, Terasen Gas will also review the following:

- Expenditures of Terasen Gas, if any, related to Terasen Gas (Vancouver Island), identifying those expenditures related to efficiency initiatives and related benefits achieved or forecast to accrue to Terasen Gas;

- Any initiatives that Terasen Gas proposes to undertake or has undertaken that may materially affect Terasen Gas operations, costs or services in a manner not anticipated or disclosed during the Negotiated Settlement Process, except where the Commission determines that public disclosure of such information at the Annual Review may harm Terasen Gas business interests and such harm outweighs the public interest in public disclosure;

- Service Quality Indicator results;

- Compliance with Terasen Gas Code of Conduct and Transfer Pricing Policy;

- Compliance with Commission directives and other regulatory requirements relevant to the Settlement;

- Opportunities, if any, to establish incentives that would assist Terasen Gas to reduce its non-controllable expenses; and.

- The number and types of customer complaint calls to CustomerWorks pertaining to the service provided by Terasen Gas.

Terasen Gas will hold its first Annual Review in November of 2003. At that Annual Review forecasts for 2004 will be presented, together with the projected number of customers at January 1, 2004 and projected plant balances and other rate base information as at January 1, 2004. Cost drivers for 2004 will be updated to reflect the most recent forecasts for 2004. Rates for 2004 will be set by the Commission based on the projected opening rate base for 2004 and the forecasts for 2004 as agreed upon by the participants or as subsequently determined by the Commission. Three weeks before each Annual Review, Terasen Gas will provide interested parties and the Commission with: (1) the projections and forecasts to be presented by Terasen Gas at the Annual Review; (2) information addressing issues of concern previously communicated to Terasen Gas by interested parties; and (3) a report on the results of the uncontrollable / partially controllable expenses for which an incentive mechanism has been established. Parties may submit information requests and Terasen Gas will respond to those requests before the Annual Review.

In regard to projected year-end earnings in the November Annual Review, Terasen Gas will provide an update in April or May once actual results have been determined and adjustments will be made at the following year end. Incentives will be trued up to the actual results at that time.

Service Quality Indicators

Service Quality Indicator results will be reviewed at the Annual Review together with a discussion of any specific initiatives undertaken to improve the SQIs or any emerging changes in customer practices that are affecting or may affect SQIs during the Term of the Settlement.

<u>Principle:</u>

Maintenance of existing high levels of service quality is an important feature of this Settlement. The parties recognize that variance in these statistics may occur due to random events or events beyond the full control of Terasen Gas.

<u>Process:</u>

- Service Quality Indicators will be reviewed at the Annual Review in November of each year.

- Participants will be given an opportunity to argue whether a deviation from the benchmark for any of the Service Quality Indicators is significant enough to establish that service quality is deteriorating generally or in specific areas.

<u>Service Quality Indicators:</u>

The parties to agree to the following SQIs and benchmarks:

1.	Response time to site from time of dispatch for emergency calls	21.1 minutes
2.	Percent of responses within 30 seconds by a person for an emergency call	95%
3.	Percent of responses within 30 seconds by a person for a non-emergency call	75%
4.	Transmission system annual reportable incidents	2
5.	(a) Percent of customer bills produced meeting activity criteria	5[1]
	(b) Percent of transportation customer bills accurate	99.5%
6	Percent of meter exchange appointments met	92.2%
7.	Percent of time when transportation meter measurement first report deviates less than 10% when compared to billable amount[2]	90.0%[3]

The parties agree that the SQIs are intended to track Terasen Gas service quality, but acknowledge that the final three SQIs listed below in particular can be influenced by high gas costs and other events beyond the control of Terasen Gas. The three SQIs listed below will be compared to previous years performance, recognizing the impact of events beyond the control of Terasen Gas.

[1] The benchmark of 5 refers to the average of the formula results for the following three submeasures, where PA refers to the actual percentage achieved for each submeasure:

	Submeasure	Formula	Benchmark PA	Benchmark Formula Result
1.	Percentage of bills accurate based upon input data	(100%-PA)*5000	99.9%	5.0
2.	Percentage of bills delivered to Canada Post within two days of date that the statement file is created	(100%-PA)*100	95%	5.0
3.	Percentage of customers billed within two business days of the scheduled billing date	(100%-PA)*100	95%	5.0

[2] Includes both daily and monthly meter measured transportation customers

[3] Calculated on a weighted average based on the number of GJ consumed by each transportation customer

8. Independent Customer Satisfaction Survey

9. Number of Customer Complaints to the BCUC

10. Number of prior period adjustments regarding transportation customer measurement data.

The parties also agree to establish the following directional indicators:

- ♦ Leaks per kilometre of distribution mains
- ♦ Number of third party distribution system incidents

<u>Annual Evaluation:</u>

- ♦ Directional indicators will be given a lesser weight in considering Terasen Gas service quality performance.

- ♦ The onus of establishing that a benchmark has been met or why it is reasonable that it was not met rests with Terasen Gas.

- ♦ Each SQI will be evaluated on its own merits and a material deviation from the benchmark for any single performance indicator that cannot be explained by events beyond Terasen Gas control is sufficient basis to argue service quality deterioration.

- ♦ Any party may argue that the benchmarks or service quality indicators need to be modified. Any proposed changes to SQIs or benchmarks must be approved by the Commission.

Compliance with the Negotiated Settlement

<u>Principle:</u>

Terasen Gas compliance with regulatory requirements and conduct as a regulated utility will be reviewed at each Annual Review.

<u>Process:</u>

At each Annual Review, Terasen Gas will provide the report required by and filed with the Commission summarizing the results of the annual compliance review of the Code of Conduct and Transfer Pricing Policy of the Commission conducted by Terasen Gas Internal Audit Services.

For each year during the Term of the Settlement, the Commission will provide Stakeholders with the proposed Commission directions to Terasen Gas Internal Audit Services. Any Stakeholder may request the Commission to add directions to review and report on other areas of concern. To assist the Commission in deciding on the merits of such a request relative to the additional cost and effort, the interested party must explain the reasons in support of the additional audit inquiry.

In addition, before the first Annual Review, Terasen Gas independent external auditor will review the work performed by Terasen Gas Internal Audit Services and at the first Annual Review, consistent with Section 8600 of the CICA Handbook Review of Compliance with Agreements and Regulations , will provide a report of Terasen Gas compliance with the Code of Conduct and Transfer Pricing Policy. Subsequent to the first Annual Review, Stakeholders and Terasen Gas may make submissions to the Commission regarding whether or not such a review and report by the independent external auditor of Terasen Gas should be continued for other Annual Reviews.

Any Stakeholder or the Commission Staff may raise for discussion at the Annual Review any action by Terasen Gas that contributed to service quality deterioration or the occurrence of an event that materially affected Terasen Gas operations, costs or services in a manner not anticipated or disclosed during the process leading to the Settlement. In the event that any such issue is not resolved in the Annual Review, participants involved in the Annual Review will have the right to ask the Commission to do one or more of the following:

a) limit the payments that Terasen Gas might otherwise earn from the financial incentive in the Settlement;

b) request the external auditor of Terasen Gas to conduct a specific enquiry on the matter in issue in the complaint and report back to the Commission; or

c) review the terms of the Settlement to determine if the Settlement should be adjusted or terminated.

Improvements to the Annual Review

Interested parties may make submissions to the Commission on items they wish to have included on the agenda for the Annual Review.

To ensure that the Annual Review continues to meet its objectives under the Settlement, Terasen Gas or any interested party may make submissions to the Commission on revisions or improvements to the Annual Review process.

APPENDIX 3

Terasen Gas Inc.
2004 — 2007 PBR Plan
Capital Expenditures True-up Process and End-of-term Benefit Phase-out

Similar to the 1998 — 2001 PBR Plan the 2004 - 2007 plan includes a process for truing up earnings sharing amounts to actual and a capital-related incentive that carries beyond the end of the PBR Term. The 1998 — 2001 Plan also included a process for adjusting the O&M expenses allowed by the formula in future years for the actual customer counts. The same customer count adjustment process will apply to the O&M formula in the 2004 — 2007 Plan but, in addition, it will also be applied to capital expenditures. The allowed capital expenditures will not be rebased to actual during the term but will be adjusted for projected and actual customers as these become known. Also, the accumulated capital benefit at the end of the term will be phased out by factors of 2/3 in the first year after plan expiry and 1/3 in the second year after.

The capital target adjustments and true-up arising from customer count variances will be carried into the subsequent years formula rate base during the PBR term but the forecast rate base for earnings sharing in each year will remain at the original target level. Customer additions variances have only a minor effect on revenue requirement within the first year. The first year additional costs and partial year of revenues from the customer variances are close to offsetting one another. The Company responded to a question on this issue in the November 1999 Annual Review of the previous PBR.

Two tables are attached which provide an example of the treatment of capital in the 2004 - 2007 PBR Plan. The first illustrates the adjustment and true up processes for customer count related variances. The second provides a simplified example (using data from the first table) of the capital benefits end of term phase-out.

Table 1: Capital Expenditures Adjustment / True-up Process

Each year will have forecast, projected and actual target base capital expenditures which result from the different number of customer additions and average number of customers.

The initial 2004 forecast will be set in the November 2003 Annual Review based on forecast number of customer additions, forecast average number of customers, forecast CPI (BC), and 50% of forecast CPI adjustment factor. Subsequently, the 2004 target expenditures will be adjusted in the following year s November 2004 Annual Review for the projected customer additions and projected average number of customers. Then once the year is complete the trued-up 2004 target base capital expenditures will be calculated based on the year s actual customer additions and average number of customers.

Assumed amounts for the actual spending in the customer additions-related and all other base capital categories are also shown in Table 1 (Lines 14 and 26). This is to illustrate how the amount of capital for phase-out at the end of the term will be determined. (Projected actual capital spending is included for 2007 in Column 13, Lines 14 and 26 since the capital benefit amount for phase-out will initially be set before the 2007 actual results are known. The capital benefit for phase out will be trued up for the actual 2007 results in the second year after the term.)

Example: November 2005 Annual Review for 2006 Revenue Requirements

At the November 2005 Annual Review the forecast for the 2006 base capital expenditures will be made using the latest 2006 forecast number of customer additions, forecast average number of customers, forecast CPI (BC), and the 66% of forecast CPI adjustment factor. Also, at this time the 2005 formula capital expenditures for rate base will be adjusted based on the projected 2005 customer additions and projected average number of customers. As well, at this time the trued-up 2004 formula base capital expenditures based on the actual 2004 customer additions and average number of customers will be known. For the calculation of the 2006 rates the 2006 rate base will therefore include the trued-up 2004 formula capital expenditures, the projected 2005 formula capital expenditures, and the forecast 2006 formula capital expenditures.

<u>Table 2: Capital Expenditure Variances for Phase-out after the Term</u>

In Table 2 the phase-out of capital benefits at the end of the PBR term is illustrated. The variances eligible for the phase-out are carried forward from Table 1. The phase-out is calculated using the 14% benefit factor. During the term of the settlement the benefits of the capital savings are shared 50/50 (through the earnings sharing mechanism) between customers and the Company. After the term customers retain their 50% share of the benefit of capital savings and additionally receive one third of the Company s 50% share in the first year after, 2/3 in the second year after and the full benefit in the third year after. The Company retains 2/3 of its 50% share in the first year after expiry of the plan and 1/3 of its 50% share in the next.

TERASEN GAS INC. ATTACHMENT
2004 -2007 PBR PLAN TABLE
TABLE 1: BASE CAPITAL EXPENDITURES
CAPITAL FORECAST ADJUSTMENT AND TRUE-UP PROCESS

Line No.	Particulars	Decision 2003	2004 Forecast	2004 Projected	2004 Actual	2005 Forecast	2005 Projected	2005 Actual	2006 Forecast	2006 Projected	2006 Actual	2007 Forecast	2007 Projected	2007 Actual
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Forecast CPI (BC)		1.80%			2.00%			2.00%			2.00%		
2	Adjustment Factor		0.90%			1.00%			1.32%			1.32%		
3														
4	CPI -AF Factor		100.90%			101.00%			100.68%			100.68%		
5														
6	**CUSTOMER ADDITION DRIVEN CAPITAL EXPENDITURES**													
7														
8	Customer Addition Driven Capital Expendture Per Customer Addition	$2,093.04	$2,111.88	$2,11188	$2,111.88	$2,133.00	$2,133.00	$2,13300	$2,147.50	$2,147.50	$2,147.50	$2,162.10	$2,162.10	$2,162.10
9														
10	Number of Customer Additions	9,265	8,459	9,500	10,000	8,521	8,300	8,000	8,793	8,800	9,000	8,864	9,000	9,100
11														
12	**Target Customer Addition Driven Expenditure ($000)**	**$19,392**	**$17,864**	**$20,063**	**$21,119**	**$18,175**	**$17,704**	**$17,064**	**$ 18,883**	**$18,898**	**$19,328**	**$ 19,165**	**$19,459**	**$19,675**
13														
14	**Actual Customer Addition Driven Capital Expenditures ($000)**				**$20,000**			**$17,500**			**$17,500**		**$17,500**	**$17,000**
15														
16	**Customer Addition Driven Capital Expenditures Variance - (Savings) / Deficit ($00)**				**($1,119)**			**$436**			**($1,828)**		**($1,959)**	**($2,675)**
17														
18	**OTHER BASE CAPITAL EXPENDITURES**													
19														
20	Other Base Capital Expendture Per Customer	$85.69	$86.46	$86.46	$86.46	$87.32	$87.32	$87.32	$87.91	$87.91	$87.91	$88.51	$88.51	$88.51
21														
22	Average Number of Customers	775,492	783,070	783,591	783,841	793,433	793,322	793,172	801,569	801,572	801,672	810,604	810,672	810,722
23														
24	**Target Other Base Capital Expenditures ($000)**	**$66,454**	**$67,704**	**$67,749**	**$67,771**	**$69,283**	**$69,273**	**$69,260**	**$70,466**	**$70,466**	**$70,475**	**$71,747**	**$71,753**	**$71,757**
25														
26	**Actual Other Base Capital Expenditures ($000)**				**$66,500**			**$68,000**			**$68,000**		**$67,000**	**$69,000**
27														
28	**Other Base Capital Expenditures Variance -(Savings) / Deficit ($000)**				**($1,271)**			**($1,260)**			**($2,475)**		**($4,753)**	**($2,757)**
29														
30														
31	**SUMMARY CAPITAL EXPENDITURES ($000)**													
32														
33	Target Customer Addition Driven Capital Expenditure		$17,864	$20,063	$21,119	$18,175	$17,704	$17,064	$18,883	$18,898	$19,328	$19,165	$19,459	$19,675
34	Target Other Base Capital Expendtures		67,704	67,749	67,771	69,283	69,273	69,260	70,466	70,466	70,475	71,747	71,753	71,757
35														
36	**Total Target Base Capital Expenditures**		**$85,568**	**$87,812**	**$88,890**	**$87,458**	**$86,977**	**$86,324**	**$89,349**	**$89,364**	**$89,803**	**$90,912**	**$91,212**	**$91,432**
37														
38	**Total Actual Base Capital Expenditures**				**86,500**			**85,500**			**85,500**		**84,500**	**86,000**
39														
40	**Total Capital Expenditures Variance - (Savings) / Deficit**				**($2,390)**			**($824)**			**($4,303)**		**($6,712)**	**($5,432)**
41														
42	**CUMULATIVE CAPITAL EXPENDITURES VARIANCE FOR PHASE-OUT**				**($2,390)**			**($3,214)**			**($7,517)**			**($12,949)**

TERASEN GAS INC. ATTACHMENT 3
2004 - 2007 PBR PLAN TABLE 2
TABLE 2: END-OF-TERM CAPITAL INCENTIVE MECHANSIM
ILLUSTRATIVE EXAMPLE
$000

Line No.	Particulars	2004	2005	2006	2007	2008	2009	2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	a). Formula Base Capital Expenditure Spending							
2	Customer Addition Driven Capital Expenditures	$21,119	$17,064	$19,328	$19,675			
3	Other Base Capital Expenditures	67,771	69,260	70,475	71,757			
4	Total Base Capital Expenditures - Final Target per formula	$88,890	$86,324	$89,803	$91,432			
5								
6	b). Actual Base Capital Expenditures							
7	Customer Addition Driven Capital Expenditures	$20,000	$17,500	$17,500	$17,000			
8	Other Regular Capital Expenditures	66,500	68,000	68,000	69,000			
9	Total Base Capital Expenditures - Actual	$86,500	$85,500	$85,500	$86,000			
10								
11	c). Capital Expenditures Variance for Phase-out							
12	Customer Addition Driven Capital Expenditures	($1,119)	$436	($1,828)	($2,675)			
13	Other Regular Capital Expenditures	(1,271)	(1,260)	(2,475)	(2,757)			
14	Total Base Capital Expenditures Variance for Phase-out	($2,390)	($824)	($4,303)	($5,432)			
15								
16	d). Cumulative Capital Expenditures Variance for Phase-out	($2,390)	($3,214)	($7,517)	($12,949)			
17								
18	e). Capital benefit @ 14%	($335)	($450)	($1,052)	($1,813)			
19								
20	Customer portion (50/50 during term, Total benefit less phase-out after)	($167.5)	($225.0)	($526.0)	($906.5)	($1,208.7)	($1,510.8)	($1,813.0)
21								
22	Company portion (50/50 during term, 2/3 & 1/3 Phase-out after)	($167.5)	($225.0)	($526.0)	($906.5)	($604.3)	($302.2)	$0.0

APPENDIX 4

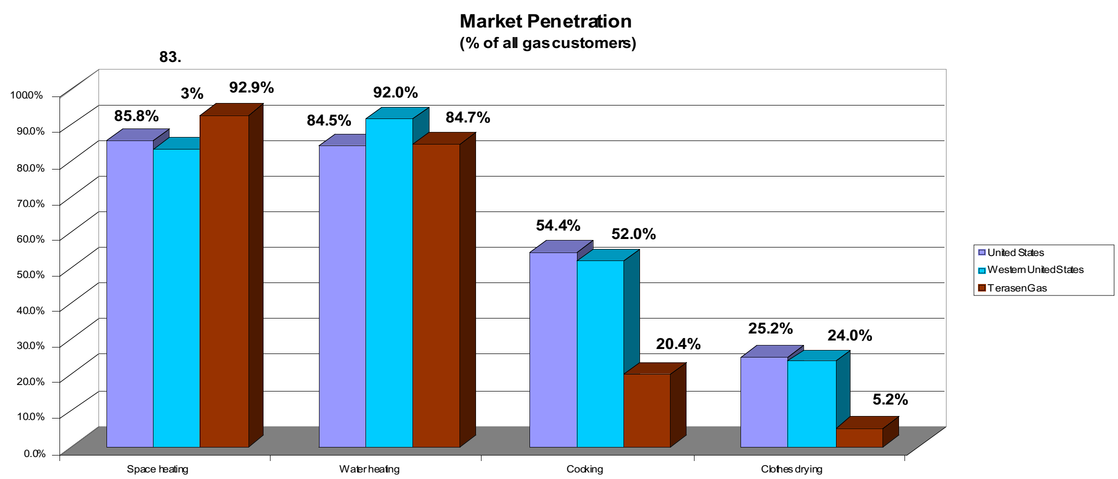
Terasen Gas Inc.
2004 — 2007 PBR Plan
Load Building Mechanism

Description of Proposal

A mechanism during the period of the PBR agreement for Terasen Gas to implement load building programs for residential and commercial customers. (i.e. primarily Rates 1 and 2 customers).

Areas of Opportunity

Examples include but are not limited to increasing the market penetration of appliances in residential households that currently use natural gas and encouraging new customers to add additional appliances. Gas appliances with potential for increased market penetration include, ranges, dryers and to a lesser extent water heaters [1].



How Does This Benefit Customers?

Increased load generates higher use per account and distribution margin.

The Proposed Load Building Mechanism

1. Using coupons, track the number of gas appliances added through a load building program each year of the program.
2. Calculate total annual load added by multiplying the average annual use rate for each appliance by the number of gas appliances added for the year.
3. Under the current RSAM mechanism, any incremental distribution margins associated with added appliance load is returned to customers through the RSAM deferral account, as the actual annual use rate would be higher, all other things being equal, than that of the use rate for RSAM determination due to the added load . Subsequent year use rate adjustments build this savings into rates prospectively.

[1] Stats for United States based on AGA survey Patterns in Residential Natural Gas Consumption Since 1980 dated Feb 11, 2000.

4. Terasen Gas proposes instead to transfer the new load related distribution margin from the RSAM deferral account to a separate revenue account for load building initiatives. The revenue recorded in this account will be included in the determination of Earning Sharing proposed under the PBR agreement (i.e. 50/50).
5. Incremental O&M expenditures incurred to support the load building programs will similarly be subject to Sharing.
6. For subsequent years of the PBR agreement, a new Load Building deferral account will be established and the new load revenues will be debited to this deferral account and credited to the new revenue account. Customer use rates for RSAM purposes will be adjusted upwards at the annual review to account for the new load, which will have the effect of increasing use per account (and thereby reducing customers rates), and the Load Building deferral account will be amortized over all customer classes ensuring non-cross subsidization. The revenues recorded in the load building revenue account are shared through the Earnings Sharing mechanism.
7. The Company proposes that customers and Terasen Gas will share equally in the benefit of load added during each year and for four subsequent years (ie. the Load Building Incentive would survive the PBR term). Thereafter, for the balance of the life of the added appliances, the full benefit of the incremental load will be fully taken into account in the use rate for RSAM determination.

APPENDIX 5

Terasen Gas Inc.

2004 — 2007 PBR Plan
Property Taxes and Incentive Proposal

Property taxes are a complex area affected by multiple levels of government (municipal, provincial, First Nations) and several different pieces of legislation (Local Government Act, Vancouver Charter, Local Services Act, BC Assessment Authority Act, Indian Act and others).

For most classes of utility property, the main factors which determine the amount of property taxes are the assessed values and the mill rates.

Within municipalities most distribution-related plant assets (mainly distribution mains and service lines) are exempt from general municipal taxes. Instead the Company pays to each municipality a tax of 1% of the revenues collected from customers within that municipality. The rate for the Vancouver is higher at 1.25 %. This tax is commonly referred to as the 1% in Lieu tax.

For 2004 the forecast for the 1% in Lieu tax is $12,745,000 and the forecast for all other property taxes is $26,170,000

Property Tax Incentive Proposal

Based on intervenor suggestions that a positive property tax incentive would be in customers interests, the Company has developed the following proposal:

For purposes of the incentive:

- Property taxes will be divided between the 1% in Lieu and all other categories (i.e., those which are based on assessed values and mill rates)

- For the 1% in Lieu taxes the incentive will be 10% of the savings related to achieving a reduced rate for the tax or a changed structure to the tax which lowers the amount payable, e.g.
  - If the In Lieu rate was reduced to 0.75% instead 1% (or for Vancouver from 1.25% to 1%), or
  - The In Lieu tax was based on delivery margin rather than the full rate including gas costs at a rate that reduces the total amount of In Lieu taxes payable to more historic levels.

- For the balance of property taxes (General, School, First Nations and other) a modified version of the formula-based approach applicable to O&M expenses and net gas plant in service will be applied.
  - The prior year actual amount will form the base to which the customer growth, inflation and inflation offset factors will be applied to determine the target for the year.

- The Company will be entitled to keep 10% of the amount by which its actual taxes are lower than the target.
  For illustrative purposes assume 2004 forecast is equal to 2004 actual. The 2005 target cost would be:

  $26,170,000 x (1 + customer growth) x (1 + CPI (BC) - 50% of CPI (BC))
  $26,170,000 x (1.0109) x (1 + 2% - 1%) = $26,720,000

  If 2005 actual property taxes were $26,400,000 the Company would retain 10% of the $320,000 difference or $32,000.

- In each case the Company shall be entitled to receive the 10% incentive payment in each year during the PBR term where the specific savings achieved continues.

- If property taxes for the year increase beyond target levels (or rates for the 1% in Lieu), there will be no penalty. The target for the following year will use this higher actual level as the base to which the growth, inflation and offset factors will be applied.

COUNT 21 1-Terasen Gas Inc.-Performance-Based Rate Plan 2004-2008-Registered Intervenor

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TGI-04/08PBR-Lower Mainland Large Gas Users Assocation; Heating Ventilating Cooling Industry Assoc. of BC; BC Greenhouse Growers Association; United Flower Growers Association; Avista Energy

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July 17, 2003

British Columbia Utilities Commission
Box 250
Sixth Floor, 900 Howe Street
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V6Z 2N3

VIA EMAIL

Attention: William J. Grant, Executive Director

Re: Terasen Gas Inc.
<u>Negotiated Settlement</u>
<u>2004-2007 PBR Plan</u>

Further to our letter of July 4, 2003, R.T. O Callaghan & Associates Inc., on behalf of BC Health Services, accepts the Terasen Gas negotiated settlement package sent with your covering letter dated July 11, 2003.

Sincerely,

R.T. O Callaghan

Pacific Western Energy Inc.
SERVING INDUSTRY & GOVERNMENT SINCE 1992

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T. 604-264-9147
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July 11, 2003

Mr. W. J. Grant
Executive Director
British Columbia Utilities Commission
900 Howe St
Vancouver ,BC V6Z 2N3

Dear Mr. Grant

Re: Terasen Gas Inc. – Negotiated Settlement
2004-2007 PBR

Further to your letter of July 8, 2003, the Elk Valley Coal Corp., ("Elk Valley"), Canada's largest producer of metallurgical coal and the world's second largest producer of metallurgical coal for export, participated in the negotiated settlement process, the results of which are attached to your letter of July 8, 2003.

As you appreciate, the negotiated settlement is the end result of an arduous negotiation process,with" give and take "from all participants, which commenced with the Application by Terasen Gas dated April 17, extended over several months, culminating in the aforementioned settlement document.

Elk Valley accepts this Agreement and its components as presented.

Yours truly,

J. David Newlands

cc: Don Shyluk, Vice President, Projects and Development.

The
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Public Interest
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Via fax and mail: 604-660-1102

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July 11, 2003

William J. Grant
BC UTILITIES COMMISSION
6th Floor - 900 Howe Street
Vancouver, BC V6Z 2V3

Dear Mr. Grant:

Re: Terasen Gas Inc. (formerly BC Gas Utility Ltd.) Negotiated Settlement 2004-2007 PBR Plan

Further to your letter of July 8, 2003, we confirm the acceptance of BCOAPO *et al.* to the Negotiated Settlement Agreement and Annual Review document on the Terasen Gas Inc. 2004-2007 Performance Based Rate Plan.

Yours sincerely,

BC PUBLIC INTEREST ADVOCACY CENTRE

for Richard J. Gathercole
Executive Director

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Reply Attention of:	David Bursey
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Email:	dwb@bht.com
Our File:	99-5939
Date:	July 11, 2003

BY E-MAIL

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

Attention: Rob Pellatt

Dear Sirs/Mesdames:

Re: Terasen Gas Inc. - Negotiated Settlement 2004-2007 PBR Plan
- BCUC Order G-29-03

Further to the Commission's letter dated 8 July 2003, I am writing on behalf of Weyerhaeuser Company Ltd., Teck Cominco Metals Ltd., Celgar Pulp Company and Canadian Forest Products Ltd. (collectively referred to as the "Inland Industrials") to confirm that the Inland Industrials accept the proposed Settlement that was attached to the Commission's letter.

The Inland Industrials thank the Commission staff, Terasen and the other customer representatives for their efforts during these negotiations.

Yours truly,

Bull, Housser & Tupper

(original signed by)

David Bursey

dwb/1128072

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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July 11, 2003

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

Attention: Mr. W.J. Grant
Executive Director

Dear Sir:

Re: Terasen Gas Inc. (formerly BC Gas Utility Ltd.)
2004 – 2007 Performance Based Rate Plan
Negotiated Settlement Agreement

Terasen Gas Inc. ("Terasen") has reviewed the revised Negotiated Settlement Documents including appendices, circulated on July 9, 2003, arising from the Negotiated Settlement Proceeding (the "NSP") which commenced on June 9, 2003 for three consecutive days and thereafter held intermittently until June 23, 2003 at the Commission office in Vancouver, B.C.

Terasen believes that the Settlement Documents are a fair and accurate representation of the settlement discussions. It is important to recognize that the settlement is the culmination of negotiations among parties having many diverse interests. The settlement represents numerous compromises among the parties and an overall balance of interests from which no part can be severed. Subject to these considerations, Terasen accepts the contents of the Settlement Documents, as revised, in their entirety.

Yours very truly,

TERASEN GAS INC.

Original signed by Scott Thomson

Scott Thomson

c. Mr. David Bursey
Mr. Richard O'Callaghan
Mr. Richard Gathercole
Mr. Chris Weafer
Mr. David Newlands

OWEN • BIRD

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Our File: 09756-0020

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 800 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Robert J. Pellatt

Dear Sirs/Mesdames:

Re: Terasen Gas Inc. (formerly BC Gas Utility Ltd.) — Negotiated Settlement 2004-2007 PBR Plan

We are counsel to the BC Greenhouse Growers Association, the United Flowers Co-operative Association, the Lower Mainland Large Gas Users Association, the Heating Ventilating Cooling Industry Association of BC (HVCI) and Avista Energy (the Stakeholders). Attached please find the Stakeholders dissent to the above-noted Negotiated Settlement.

A copy of this letter and attached Information Request will be forwarded to the intervenors by e-mail as well as by facsimile and mail to those who did not provide an e-mail address.

Yours truly,
OWEN, BIRD

Christopher P. Weafer

Christopher P. Weafer
CPW/jlb
Encl.
cc: Registered Intervenors
cc: Terasen

DISSENT ON NEGOTIATED SETTLEMENT
ON BEHALF OF THE
THE LOWER MAINLAND LARGE GAS USERS ASSOCIATION,°
BC GREENHOUSE GROWERS ASSOCIATION,°
THE UNITED FLOWER GROWERS CO-OPERATIVE ASSOCIATION, °
HEATING VENTILATING COOLING INDUSTRY ASSOCIATION OF BC, and°
AVISTA ENERGY CANADA LTD.
(the Stakeholders)

IN THE MATTER OF THE UTILITIES COMMISSION ACT, °
R.S.B.C. 1996, CHAPTER 473

AN APPLICATION BY TERASEN GAS INC. (FORMERLY KNOWN AS BC GAS UTILITY LTD.) FOR APPROVAL OF A MULTI-YEAR PERFORMANCE-BASED RATE PLAN TO SET RATES FOR 2004 - 2008

The Stakeholders, who participated in the above-noted settlement, represent the following industries:

1. Lower Mainland Large Gas Users Association which represents 18 large industrial end users and institutional end users located in the Lower Mainland of British Columbia;

2. Heating Ventilating Cooling Industry Association of BC (HVCI) which represents the residential heating industry operating in the Province of British Columbia;

3. BC Greenhouse Growers Association which represents the British Columbia greenhouse industry;

4. United Flower Growers Co-operative Association which represents the flower growing industry of British Columbia; and

5. Avista Energy Canada Ltd., a gas marketing and energy services company which represents more than 200 commercial and industrial customers resident in the Province of British Columbia.

Each of the above Stakeholders has been an active participant in Terasen Gas Inc. (Terasen) related matters and they represent a broad, comprehensive and diverse set of interests as customers and competitors with Terasen. Notwithstanding the diversity of their operations, the Stakeholders share a strongly held common concern about the regulatory model being used in regard to Terasen.

I. Background

Each of the Stakeholders have a common concern about the value of performance based regulation (PBR). The Stakeholders entered into this negotiation process a strongly held belief that cost of service regulation and annual cost of service reviews have at least as many benefits to customers as does PBR. This Stakeholder group will not be surprised if PBR is ultimately found to not conserve the public interest.

The Stakeholders were particularly concerned with and remain opposed to long term PBR settlements which essentially remove Terasen from the review of the British Columbia Utilities Commission (the Commission) in any substantive sense for long periods of time. While the detail of this opposition in regard to Terasen will be set out later in this document, it is also the position of the Stakeholders that notwithstanding some policy support for PBR reflected in Commission decisions and in some provincial government directions, long term PBR is inconsistent with Policy Action Number 12 in the Province s Energy Plan entitled Any Energy for our Future: A Plan for BC which provided the structure of the Commission, and its mandate in regulating Terasen and other energy distributors, will be strengthened. Simply put, the above-noted Stakeholders fail to see how the Commission is being strengthened by providing long term PBR settlements which remove the Utility from a more indepth review and transparent access to economic issues affecting end users.

The Stakeholders have a serious concern with respect to the manner in which the prior PBR settlements resulted in Terasen returning significant benefits to its shareholders in that the price of the Terasen stock doubled during the last PBR term, during the same time period the utility s appetite for passing on cost increases and risks to customers through flow through and deferral accounts was prevalent. The Stakeholders do not have a problem with the financial success of Terasen in the investment community; however, when one reviews Terasen s relationship with the Stakeholder group represented in this submission, a relationship of mistrust and cynicism has evolved during the past PBR periods.

The Stakeholders understand the issues that Terasen faces responding to the investment market place on an on-going basis with quarterly reporting requirements and a need to maintain a positive profile in the investment market. The fear of the Stakeholders is that upon being granted a long term settlement, the interest to comply with utility regulatory requirements, including Code of Conduct, will significantly reduce and various incentives will conflict utility customer interests with those more designed to respond to the investment market.

This cynical view is based on the past record during the PBR period where various costs flowed through to customers more than offsetting any promised PBR benefit. More importantly, the cynicism is reinforced when one looks at the response of Terasen to the directions of the Commission set out in the Commission s decision of February 4, 2003 on Terasen s revenue requirement. The test of commitment to meet regulatory objectives is best determined by review of the most recent conduct of Terasen.

II. Compliance with February 4, 2003 Decision of the Commission

(a) Transfer Pricing Policy

The seriousness with which Terasen takes its utility regulatory requirements is questioned by the Stakeholders. When one reviews the February 4, 2003 decision of the Commission and the response of Terasen to directions set out in that decision, that scepticism is reinforced. At pages 43 to 45 of the February 4, 2003 decision, the Commission set out its determination with respect to Code of Conduct and Transfer Pricing Policy (TPP) indicating that the evidence adduced in the hearing suggests that Terasen has not treated the TPP with sufficient seriousness and care. During the hearing the Commission could not determine that there was always an appropriate distinction between utility activities and cost, and non-utility activities and cost . In response to Lower Mainland Large Gas Users Association s Information Request No. 1 at Appendix C, in this proceeding Terasen set out its response to dealing with the TPP guidelines.

At slide 5 of Appendix C entitled T PP Explained , Terasen sets out how they have instructed their employees to charge either fully allocated cost or market price (not the higher of the two).

The Commission s decision states at page 41, paragraph 2, that BC Gas was concerned specifically about the requirement in TPP to charge the greater of the market price or the fully allocated cost of services supplied to NRBs .

When one reviews the slides presented by management of Terasen to employees in explaining the TPP, it provides that the pricing rules for utilities is based on: full cost or market price . This is not the Transfer Pricing Policy guidelines in that the pricing is to be the greater of full cost or market price.

The Commission also dealt with the issue of incremental pricing of services which is neither fully allocated cost nor market cost pricing. At the revenue requirement hearing, Commission council cross-examined Terasen on incremental pricing and questioned that if the incremental pricing was zero (as Terasen said the website work was), would there be no charge for the service? Terasen answered in the affirmative.

The incremental price issue is seen in the Grey Area section of the slide show presented in response to the above-noted information request. At slides 11 and 12 entitled My Work it instructs employees as follows: If work seems to relate to both utility and NRB or Inc., consider the context: if NRB did not exist, would Utility still do this work? The question implies that the answer is yes , then incremental cost of zero should be applied to the work. The question which should be asked in order to apply TPP correctly — is fully allocated cost or market price whichever is greater - is the NRB or Inc. receiving value for my work? If the answer is in the affirmative, then the fully allocated or market price, whichever is greater, should be applied.

In conclusion on this point, it is apparent to the Stakeholders that on this issue considered by the Commission in the public hearing, Terasen has not complied with the direction of the Commission and has remained vague and unclear in instructing its employees on this important issue contrary to the direction of the Commission.

(b) Referral of Customers

Further, the information filed in response to Lower Mainland Large Gas Users Information Request No. 1 at Appendix C indicates that Terasen is still referring customers to Terasen NRB s and specific retailers in that the slides indicates that the caller should be directed to two alternative service providers when a referral is made to an NRB. Page 4, Item 6 of the Terasen s Code of Conduct specifically states that BCGUL will not preferentially direct customers seeking competitively offered services to an NRB or a specific retailer . It is significant that Terasen requested this item be removed from the Code of Conduct in their 2003 revenue requirement application, then dropped the request, yet is instructing their employees to preferentially direct customers to NRBs and specific retailers. Again, it is an example of where a matter was dealt with in some detail and with some serious level of concern at the hearing process, directions arise in the decision of the Commission, and Terasen appears to be attempting to avoid compliance with the direction. This is not conduct which supports lessening the regulatory oversight of the utility.

(c) Compliance with Commission Direction on Website

A review of the website also indicates that Terasen has not taken the Commission s decision in February, 2003 seriously. This was a matter raised by HVCI and a matter that caused concern to the Commission is reflected in its decision at pages 44 to 45. A review of the Terasen website indicates that far from reducing confusion, the renaming of BC Gas Utility Ltd. to Terasen Gas and the creation of subsidiaries such as Terasen Utility Services Ltd. has created more confusion in the minds of customers. More importantly, Terasen has not responded to the direction of the Commission which was to create separate and distinct websites for Terasen Gas and Terasen, Inc. and its group of NRBs. Further, the decision indicated that there should be no direct links from the Terasen Gas website to non-regulated business activities of Terasen, Inc. Specific links from Terasen Gas to the Inland Pacific Connector and to IPCO and CIPI are, along with numerous other links, in direct contradiction to the decision of the Commission of February, 2003. If the Commission s decisions are not being fully complied with on these obvious examples, what else is being overlooked?

(d) Separation of Management Function

A further direction of the Commission was the separation out of the management function of BC Gas Inc. and BC Gas Utility Ltd. We are advised by the companies that they will provide a study at the end of August on this topic. With respect to the provisioning of a study, it is not a satisfactory response to an issue that has been in existence for some considerable period of time and the Annual Review in November will need to deal with a more significant proposal by Terasen in order to resolve this significant issue. The fear of Stakeholders is that Terasen will follow the model pursued in Ontario by other utilities in PBR periods which is to maximize return to the non-regulated business side of the company and maximize cost to the utility side. Only time will tell whether these speculations are correct. However, the risk of long term settlement increases the chance of this occurring by minimizing ongoing public scrutiny.

III. The Appropriateness for PBR

The Stakeholders have participated in negotiations around PBR with Terasen for the past eight years. These negotiations have included the filing and withdrawing of PBR applications by Terasen once it appeared that Terasen would not be successful with its filing. In one instance Terasen withdrew an approximately 17% rate increase and accepted a rate freeze and was successfully able to maintain rates at frozen levels in that year.

A common question of Stakeholders is: what incentive is really needed beyond the regulated rate of return approved by the Commission in annual reviews to ensure that management of Terasen does the job it was hired to do? Clearly the incentive compensation of management and executives is such that they should be highly motivated to perform their jobs as they are some the most well paid regulated executives in the Province, if not some of the highest paid executives in the Province. These Stakeholders fail to understand how professional utility managers would not be incented to properly and prudently run Terasen without the need to offer further incentive to shareholders. Clearly, the utility investment environment is far stronger than it was relative to the investment community on a whole as the days of 20% return on technology investments are long gone. The rapid rise of Terasen Inc. s stock price would indicate that the stability offered by utility investment is strong and here to stay. As a result, the need to offer further incentive to attract investment is significantly reduced and we fail to understand the on-going need for incentives generally. Is this an admission of regulatory flaws of an unwillingness to make business decisions that should otherwise be made without incentives?.

IV. The Integrity of the Regulatory Process

The Stakeholders remain concerned that a long term settlement reduces the Commission s and the Stakeholder s ability to maintain institutional history around the operations of Terasen. Given the long term importance of the utility operations in the Province and the need for stability over the long haul horizon, this lack of institutional record is a risk being adopted for approving long term settlements. The Stakeholders believe that a one or two year cost of service regulatory regime is efficient, effective and serves the interests of customers as well. The Stakeholders believe that no longer than three years should be approved for this settlement as sufficient recovery is provided to Terasen and a significant enough planning horizon is created to enable management to prudently and effectively run Terasen.

V. Conclusion

In conclusion, the Stakeholders do not support the negotiated settlement agreement circulated by the Commission on July 3, 2003 and specifically, the adoption of a PBR term which is in excess of four years. The Stakeholders were prepared to agree to a three year term and believe that that is the maximum term which should be available to Terasen. The Commission determined in previous reviews that a three year term was appropriate and we believe this to be the case. The Stakeholders do take some comfort in the adoption of an annual review process as set out in Appendix A to the settlement but are concerned how engaged the Commission can be considering its resources and growing work load. We trust that Terasen and the Commission will take this annual review seriously to ensure that the interests of customers are protected during this PBR period.

As indicated, the above comments are intended to reflect concern which has grown and become commonly held amongst a broad sector of customers and competitors of Terasen during the past PBR period. Commitments have been made in this negotiation process to improve this situation and the Stakeholders look forward to steps being taken to improve the relationship.

The public trust granted to a monopoly utility requires a high standard of conduct in exchange for the guaranteed rate of return enjoyed by a regulated utility.

The Stakeholders are not asking the Commission to deal with this Application through further public process but simply wish to put their concerns on the public record through this dissent.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Christopher P. Weafer

Christopher˚P. Weafer,
Counsel to: Lower Mainland Large Gas Users Association
BC Greenhouse Growers Association
The United Flower Growers Co-Operative Association
Heating Ventilating Cooling Industry Association Of BC˚
Avista Energy Canada Ltd.